ATTACHMENT 5

LICENSE AMENDMENT REQUEST
STRETCH POWER UPRATE

SPU LICENSING REPORT

DOMINION NUCLEAR CONNECTICUT, INC.
MILLSTONE POWER STATION UNIT 3

Stretch Power Uprate

Licensing Report

Millstone Power Station Unit 3

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1.0 INTRODUCTION TO THE MILLSTONE POWER STATION, UNIT 3 STRETCH POWER UPRATE LICENSING REPORT

1.0.1 General Overview of the Millstone Power Station, Unit 3 SPU Licensing Report

The MPS3 SPU LR is a technical summary of the results of the analyses and evaluations performed to demonstrate that the proposed increase in plant power can be safely achieved and that the increase will not be inimical to the common defense and security or to the health and safety of the public. The LR supports the requested license and technical specification changes by providing reviewers with a comprehensive evaluation of the effects of the proposed SPU.

The DNC evaluations have been formatted and documented in accordance with the template and criteria provided in RS-001, "Review Standard for Extended Power Uprates," Rev. 0. The LR documents the technical basis for the proposed changes necessary to implement the SPU in a sufficient detail to permit the NRC staff to reach an informed determination regarding the consistency, quality, and completeness of the evaluation with respect to the areas within the NRC's scope of review. The technical evaluations presented in the LR include, when appropriate, a discussion of SPU effects on plant operating limits, functional performance requirements and design margins and describe the methods DNC used in reaching the conclusions. DNC has included any differences between the information in the review standard and the MPS3 design bases to enhance the NRC review.

DNC used RS-001 to the extent possible and added information to the licensing report to better define the SPU effects on MPS3, as appropriate. The following are important considerations to assist in the understanding of the LR.

Summary of Plant Changes

Table 1.0-1 provides a listing of the required plant modifications and changes to setpoints and control system settings. These modifications and changes are planned to be implemented during the MPS3 Outage scheduled for October 2008 (3R12). Power escalation to the new uprate power level is planned immediately after the October 2008 outage (3R12), including performance testing upon return to power.

Table 1.0-2 is a summary of the modified accident analyses.

Section 2.8.5 describes the changes to the computer codes utilized in the accident analyses to incorporate the SPU conditions.

Current Licensing Basis

In December 2003, the NRC issued its Review Standard for Extended Power Uprate, RS-001. This LR is intended to conform, to the maximum practical extent, to the guidance of RS-001. The regulatory review criteria portion of the RS-001 section details specific NRC review and acceptance criteria. The review standard acknowledges that there can, and will, be differences between the review standard and the design basis of a particular facility. The review standard contains provisions to ensure that these differences do not impede the NRC staff's review. Consistent with the review standard, a clear and concise summary of the MPS3 CLB is provided regarding the SSC's design or analysis under review.

Each section of the MPS3 SPU LR that details a SSC or selected analysis contains a brief description of MPS3's CLB with respect to the SSC or analysis under evaluation. In addition, each LR section addresses, as applicable, the anticipated SPU impact on the license renewal evaluations.

The MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800). The LR section will identify the Standard Review Plan number, and revision that is applicable to the plant design.

Treatment of Issues Related to the Renewed Operating License

By letter dated January 20, 2004, DNC submitted to the NRC an application requesting the NRC renew the MPS3 Operating License for a period of 20 years beyond the expiration date established in the MPS3 Operating License. The NRC completed its review and approved the MPS3 license renewal application as documented in NUREG-1838, "Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3," in October 2005. SSCs subject to aging management review are discussed in SER Sections 2.3B through 2.5. For those identified SSCs, the specific applicable aging management programs are discussed in SER Sections 3.1B through 3.6.

10 CFR 54 contains the requirements for renewal of nuclear power plant operating licenses. It identifies plant SSCs that are within the scope of the rule (10 CFR 54.21), as well as requirements for performing aging management reviews of those SSCs. Additionally, the rule requires an evaluation of TLAA to account for the effects of aging on the intended functions of SSCs that are not subject to replacement based on a qualified life or specified time period. The TLAA are intended to ensure that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The operating conditions associated with the proposed SPU may change certain operating parameters such as pressure, temperature, flow, and radiation compared to current operating conditions. The SPU also introduces the possibility that components not currently within the scope of the rule (either currently installed in the plant or added as the result of SPU) may, as the result of SPU, meet the scoping criteria for inclusion detailed in the rule.

As discussed in each section of this LR, an evaluation of the SPU impact on the extended period of plant operation was performed. The purpose of this evaluation was to identify which, if any, SSCs warranted additional aging management action. These may include SSCs subject to new aging effects because of changes in the operating environment resulting from SPU or the addition of, or modification to, components relied upon to satisfy SPU operating conditions.

SSCs relied upon for achieving the license renewal scoping objectives are evaluated within the structure or system that contains them.

DNC also evaluated the potential impact of the proposed SPU on license renewal TLAA. Specifically, the evaluation considered any new aging effects or increases in degradation rates potentially created by the new SPU operating parameters. In addition to the discussion contained in the individual LR section, the impact of SPU on license renewal TLAA is further discussed in Section 2.14.

SPU Effect on Plant Programs

DNC has provided an evaluation in this LR for each of the programs that are specifically addressed in RS-001.

During the review and development of the LR, DNC identified the programs that could be impacted by the changes associated with SPU. The affected programs will be revised to reflect the changes associated with the SPU prior to or concurrent with the implementation of the license amendment associated with the SPU.

Sections within the LR in addition to those specified in RS-001

The licensing report takes advantage of the RS-001 provision to add additional sections (additional review areas). The following sections are beyond the standard template:

1.0	Introduction to the Millstone Power Station, Unit 3 Stretch Power Uprate Licensing Report
1.1	Nuclear Steam Supply System Parameters
2.2.6	NSSS Design Transients
2.2.7	Bottom Mounted Instrumentation
2.4.2	Plant Operability
2.4.3	Pressurizer Component Sizing
2.5.8	Circulating Water System
2.7.7	Other Ventilation Systems (Containment)
2.8.5	Accident and Transient Analysis Introduction
2.8.7.1	Auxiliary Systems Pumps, Heat Exchangers, Valves and Tanks
2.8.7.2	Natural Circulation Cooldown
2.8.7.3	Loss of Residual Heat Removal at Mid-loop
2.14	The Effects of SPU on the Renewed Licensing and License Renewal Programs

Use of Industry Operating Experience

Both regulators and industry peer groups strongly advocate incorporating operating experience and lessons learned as a basic input in design, maintenance and operating and licensing activities. The analysis and evaluations performed for the SPU at MPS3 took full advantage of past power uprate experience by:

- Review of NRC RAIs issued over the past several years to PWR power uprate applicants. The RAI responses relating to the subject were reviewed against the expressed concern to provide reviewer confidence that the issue was appropriately examined.
- Review of INPO generic communications, lessons learned and experience information that relates to power uprates was performed. During the analysis phase, EPRI's power uprate database, INPO OE items and sources of internal operating experience and component

history information were also reviewed, and made available to project personnel. System and program engineers were interviewed to ensure that all pertinent information was available for inclusion in SPU evaluations. Recent Plant Health Reports, LERs, Operability Determinations and other sources of internal experience were also reviewed and factored into project activities. Margins and reductions in margin were also reviewed and assessed as a part of changes made during the SPU.

- Contractor organizations experienced in previous power uprates provided support for required analysis and evaluations.
- A highly experienced project team was assembled to oversee analysis and evaluations provided by contractor organizations.
- An Executive Oversight Committee was formed to oversee SPU project plans, significant margin changes and overall progress. The committee was comprised of senior managers from the Millstone Station and Dominion Nuclear corporate offices.

Treatment of Proprietary Information referenced within the Licensing Report

Westinghouse Electric Company has identified proprietary information that is not included in this LAR. The proprietary information, along with the required affidavit, is being submitted separately to the NRC by DNC. Every effort was made to minimize the amount of information withheld; information provided within brackets, i.e., [ ], designates data that is Westinghouse Proprietary.

Table 1.0-1 MPS3 Power Uprate Planned Modifications

System/ Component	Modification Description	Reason
Main Feedwater Pump	Turbine replacement	Improves plant performance due to increased flow.
Turbine building HVAC	Modified ductwork to provide additional ventilation cooling in the condensate pump area.	Improves margin regarding temperature limits for the condensate pump motor windage.
Control building Ventilation	Control building auto initiation of pressurized filtration following Control Building isolation signal	Reduces control room dose following a fuel handling accident.
Turbine Generator	1. New operating point for generator excitation 2. Control valve position demand vs. lift settings for the valve position cards 3. Changes to power load imbalance circuits 4. Throttle pressure and excess throttle pressure circuit recalibrations 5. Sensor rescaling for steam pressure changes 6. Instrument scaling 7. Main control board & panel meter replacements	Provide proper indication for SPU conditions.

Table 1.0-1 MPS3 Power Uprate Planned Modifications

System/ Component	Modification Description	Reason
Component Cooling Water	Increase in piping design temperature between RHS and Component Cooling Water Heat Exchanger	Permits reactor cooldown.
Instrumentation & Control Systems	Setpoint changes: 1. BOP system 2. Feedwater pump 3. Pressurizer level control 4. Electronic filter on T_{hot} signal 5. PRT level alarm 6. Condenser steam dump trip valve control 7. P-8 setpoint change	1. Provides proper indication for SPU conditions 2. Improves performance regarding proper system operation 3. Supports the revised analysis regarding loss of normal feedwater and accommodate RCS shrink and swell at SPU conditions 4. Improves operational margin for observed T Hot temperature spikes 5. Supports the revised analysis regarding loss of normal feedwater and accommodate RCS shrink and swell at SPU conditions 6. Permits proper operation during SPU conditions. 7. Improves performance regarding proper system operation.
Pipe Support Modifications: Condensate, Feedwater Component Cooling Water, and Extraction Steam	Pipe support modifications	Improve margin regarding SPU conditions
ECCS	Permissive for opening cold leg injection valves	Permits elimination of the inadvertent ECCS analysis, due a logic that requires both an SI signal and a low RCS pressure signal to exist before automatically opening the cold leg injection valves.

Table 1.0-1 MPS3 Power Uprate Planned Modifications

System/ Component	Modification Description	Reason
Instrument Loop Rescaling	1. Isophase bus duct cooler flow 2. MSR steam flow 3. First stage turbine pressure	Provides proper indication for SPU conditions.
Rod Control System	Deletion of automatic rod withdrawal capability.	Improves EQ and DNBR margin. Eliminates possibility of steamline break with coincident rod withdrawal.
Control Building Ventilation	Control Building auto initiation of pressurized filtration following Control Building Isolation Signal	Reduces control room dose following a fuel handling accident.

Table 1.0-2 Summary of Changes to Accident Analysis Methodology

#	Impacted Accident Analysis	How Modified
1	Non-LOCA Transient Analyses (Section 2.8.5)	Methodology changed from LOFTRAN/THINC to RETRAN/VIPRE
2	DNBR Analyses (Section 2.8.5)	DNBR correlation changed from WRB-2 to WRB-2M Revised analyses incorporates installation of hot leg RTD filter and revised OPDT/OTDT setpoints
3	Steam line break at hot full power (Section 2.8.5.1.2)	Credit taken for elimination of automatic rod withdrawal capability of the rod control system.
4	Loss of Load/Turbine Trip with inoperable Main Steam Safety Valves (Section 2.8.4.2)	Revised TS limits for maximum power level with inoperable main steam safety valves.
5	Inadvertent ECCS Actuation (Section 2.8.5.5)	Credit taken for installation of SIAS permissive for Cold Leg ECCS injection valves.
6	CVCS Malfunction that Increases RCS Inventory (Section 2.8.5.5)	New analysis provided charging pump control system failure
7	Steam Generator Tube Rupture Analysis (Section 2.8.5.6.2)	Changes made in operator action assumptions.
8	Large Break LOCA (Section 2.8.5.5)	Methodology changed from BART/BASH to the Best Estimate ASTRUM analysis methodology
9	Radiological Analyses (Section 2.9.2)	Eliminated credit for operator action to trip non-safety grade ventilation fans
10	Fuel Handling Accident (Section 2.9.2)	Gap release fractions are based upon Reg. Guide 1.25 since the SPU conditions exceeds the limits for the gap releases specified in Reg. Guide 1.183. Credit taken for Control Building Emergency Ventilation system operation.
11	Containment analysis (Section 2.6.5)	Methodology changed from S&W LOCTIC to DNC GOTHIC

1.1 Nuclear Steam Supply System Parameters

The Nuclear Steam Supply System (NSSS) design parameters are the fundamental parameters used as input in all of the NSSS analyses. A portion of the current Millstone Unit 3 Station NSSS design parameters are summarized in Table 4.1-1 of the Millstone Unit 3 Final Safety Analysis Report (FSAR). The NSSS design parameters provide the primary and secondary side system conditions (thermal power, temperatures, pressures, and flows) that serve as the basis for all of the NSSS analyses and evaluations. As a result of the Stretch Power Uprate (SPU), the MPS3 NSSS design parameters have been revised, as shown in Tables 1-1 and 1-2, to represent operation following the SPU. These parameters have been incorporated, as required, into the applicable NSSS systems and components evaluations, as well as safety analyses, performed in support of the SPU.

1.2 Input Parameters, Assumptions, and Acceptance Criteria

The NSSS design parameters, also referred to as the Performance Capability Working Group (PCWG) parameters, provide the reactor coolant system (RCS) and secondary system conditions (thermal power, temperatures, pressures, and flows) that are used as the basis for the design transients, systems, structures, components, accidents, and fuel analyses and evaluations.

The code used to determine the NSSS design parameters was SGPER (Steam Generator PERformance). There is no explicit NRC approval for the code since it is used to facilitate calculations that could be performed by hand. That is, the code and method used to calculate these values have been successfully used to license all previous similar programs for Westinghouse plants. They use basic thermal-hydraulic calculations, along with first principles of engineering, to generate the temperatures, pressures, and flows shown in Tables 1-1 and 1-2.

The major input parameters and assumptions used in the calculation of the six cases of PCWG parameters established for the SPU are summarized below and in Tables 1-1 and 1-2:

- The parameters are applicable to the existing Westinghouse Model F Steam Generators (SGs).
- The uprated NSSS power level of 3666 MWt (3650 MWt core power + 16 MWt RCS net heat input) was assumed for the analyses. This is approximately 7.0 percent higher than the current NSSS power level of 3425 MWt.
- A feedwater temperature (T_{Feed}) range of 390.0° to 445.3°F was used for the analyses.
- The design core bypass flow was assumed to be 8.6 percent; this accounts for Thimble Plugs Removed (TPR) and Intermediate Flow Mixing Vanes (IFMs).
- The current Thermal Design Flow (TDF) of 90,800 gpm/loop was maintained for the analyses.
- A full-power normal operating Vessel Average Temperature (T_{Avg}) range of 571.5°F to 589.5°F was used in Table 1-1 and a full-power T_{Avg} of 581.5°F was used in Table 1-2. The T_{Avg} value of 571.5°F is 581.5°F with a 10°F full power end of cycle T_{Avg} coastdown.
- Steam Generator Tube Plugging (SGTP) levels of 0 percent and 10 percent were assumed.

- The current design SG fouling factor of 0.00006 hr-ft^2-°F/BTU was maintained.
- A maximum SG moisture carryover of 0.25 percent for sustained operation was utilized.
- The parameters are applicable to 17x17 RFA/RFA-2 Fuel.

The acceptance criteria for determining the NSSS design parameters were that the results of the SPU analyses and evaluations continue to comply with all MPS3 applicable industry and regulatory requirements, and that they provide DNC with adequate flexibility and margin during MPS3 operation.

1.3 Description of Analyses and Evaluations

Table 1-1 provides the NSSS design parameter cases that were generated and serve as the basis for the SPU.

- SPU Cases 1 and 2 of Table 1-1 represent parameters based on a T_{Avg} of 571.5°F. Case 2 yielded the minimum secondary side steam generator pressure and temperature since it was based on an average level of 10 percent SGTP. Note that all primary side temperatures were identical for these two cases.
- SPU Cases 3 and 4 of Table 1-1 represent parameters based on the T_{Avg} of 589.5°F. Case 3 yields the highest secondary side steam pressure performance conditions since it was based on 0 percent SGTP. Note that all primary side temperatures were identical for these two cases. As provided via footnote “b” of Table 1-1, for instances where an absolute upper limit steam generator outlet pressure is conservative for any analyses, these data are based on the Case 3 parameters but assume a fouling factor of zero.

Table 1-2 provides the NSSS design parameter cases that were generated and serve as the basis for the SPU lower bound of the T_{Avg} range for the DNB Transient Analyses and associated Setpoint use.

- SPU Cases 5 and 6 of Table 1-2 represent parameters based on a T_{Avg} of 581.5°F with 0 percent and 10 percent SGTP, respectively. Note that all primary side temperatures were identical for these two cases.

Best-estimate calorimetric measurement-based secondary side performance predictions were also calculated for the SPU. These calorimetric measurement-based calculations were performed to estimate the actual expected steam conditions at the steam generator outlet as opposed to the design conditions shown in Tables 1-1 and 1-2. The calorimetric measurement-based calculations used MPS3 plant measured calorimetric data from cycle 11 to determine NSSS performance. The results were used in the Balance of Plant (BOP) analyses performed for the SPU.

A simplified primary heat balance diagram is provided in Figure 1-1. This heat balance diagram illustrates the design parameters for Case 3 from Table 1-1.

1.4 Best Estimate RCS Flows

Best Estimate (BE) RCS Flows were calculated to support the SPU to determine whether adequate flow margin exists for the TDF and Mechanical Design Flow (MDF) values established. The results of the BE RCS Flow calculations are as follows:

- BE RCS Flow values of 99,700 gpm/loop at 0 percent SGTP and 97,300 gpm/loop at 10 percent SGTP.

1.5 Conclusion

The resulting NSSS design parameters (Tables 1-1 and 1-2) were used by Westinghouse as the basis for all the analytical efforts. Westinghouse performed the analyses and evaluations based on the parameter sets that were most limiting, so that the analyses would support operation over the entire range of conditions specified.

Table 1-1
NSSS PCWG Parameters for the MPS3 SPU Program

	Current (e)	7% SPU Program			
		Case 1	Case 2	Case 3	Case 4
Thermal Design Parameters					
NSSS Power, %	100	107	107	107	107
MWt	3425	3666	3666	3666	3666
10^6 Btu/hr	11,687	12,509	12,509	12,509	12,509
Reactor Power, MWt	3411	3650	3650	3650	3650
10^6 Btu/hr	11,639	12,454	12,454	12,454	12,454
Thermal Design Flow, loop gpm	90,800	90,800	90,800	90,800	90,800
Reactor 10^6 lb/hr	135.4	138.8	138.8	135.3	135.3
Reactor Coolant Pressure, psia	2250	2250	2250	2250	2250
Core Bypass, %	8.6	8.6 (a, c)	8.6 (a, c)	8.6 (a, d)	8.6 (a, d)
Reactor Coolant Temperature, °F					
Core Outlet	623.5	611.4 (c)	611.4 (c)	628.0 (d)	628.0 (d)
Vessel Outlet	618.3	605.6	605.6	622.6	622.6
Core Average	591.6	576.2 (c)	576.2 (c)	594.5	594.5
Vessel Average	587.1	571.5	571.5	589.5	589.5
Vessel/Core Inlet	555.9	537.4	537.4	556.4	556.4
Steam Generator Outlet	555.6	537.0	537.0	556.0	556.0
Steam Generator					
Steam Outlet Temperature, °F	540.7	520.4	517.8	539.9 (b)	537.4
Steam Outlet Pressure, psia	968	815	797	962 (b)	942
Steam Outlet Flow, 10^6 lb/hr total	15.04	16.20/15.03	16.19/15.02	16.30/15.12(b)	16.29/15.10
Feed Temperature, °F	436.2	445.3/390.0	445.3/390.0	445.3/390.0	445.3/390.0

Table 1-1
NSSS PCWG Parameters for the MPS3 SPU Program

	Current (e)	7% SPU Program			
		Case 1	**Case 2**	**Case 3**	**Case 4**
Steam Outlet Moisture, % max.	0.25	0.25	0.25	0.25	0.25
Design FF, hr. sq. ft. °F/Btu	0.00006	0.00006	0.00006	0.00006	0.00006
Tube Plugging Level, %	0	0	10	0	10
Zero Load Temperature, °F	557	557	557	557	557
Hydraulic Design Parameters					
Pump Design Point, Flow (gpm)/Head (ft.)	100,400/289	100,400/289			
Mechanical Design Flow, gpm	103,600	103,600			
Minimum Measured Flow, gpm/total	372,000	379,200			

Footnotes:

a. Core bypass flow accounts for Thimble Plug Removal (TPR) and Intermediate Flow Mixing Vanes (IFMs).

b. If high steam pressure is more limiting for analysis purposes, a greater steam pressure of 984 psia, steam temperature of 542.6°F, and steam flow of 16.32×10^6 lb/hr should be assumed. This is to envelope the possibility that the plant could operate with better than expected SG performance.

c. If thimble plugs are installed, the core bypass flow is 6.6%, core outlet temperature is 610.0°F, and core average temperature is 575.4°F.

d. If thimble plugs are installed, the core bypass flow is 6.6%, core outlet temperature is 626.7°F, and core average temperature is 593.7°F.

e. Current parameters obtained from FSAR Table 4.1-1, or from the most recent NSSS PCWG parameters.

Table 1-2
NSSS PCWG Parameters for the MPS3 SPU Program

	SPU Program Lower Bound of T_{Avg} Range for DNB Transient Analyses and Associated Setpoint Use			
		Case 5	Case 6	
Thermal Design Parameters				
NSSS Power, %		107	107	
MWt		3666	3666	
10^6 Btu/hr		12,509	12,509	
Reactor Power, MWt		3650	3650	
10^6 Btu/hr		12,454	12,454	
Thermal Design Flow, loop gpm		90,800	90,800	
Reactor 10^6 lb/hr		136.9	136.9	
Reactor Coolant Pressure, psia		2250	2250	
Core Bypass, %		8.6 (a, b)	8.6 (a, b)	
Reactor Coolant Temperature, °F				
Core Outlet		620.7 (b)	620.7 (b)	
Vessel Outlet		615.1	615.1	
Core Average		586.4 (b)	586.4 (b)	
Vessel Average		581.5	581.5	
Vessel/Core Inlet		547.9	547.9	
Steam Generator Outlet		547.6	547.6	
Steam Generator				
Steam Outlet Temperature, °F		531.2	528.7	
Steam Outlet Pressure, psia		894	876	
Steam Outlet Flow, 10^6 lb/hr total		16.25/15.08	16.24/15.06	
Feed Temperature, °F		445.3/390.0	445.3/390.0	
Steam Outlet Moisture, % max.		0.25	0.25	
Design FF, hr. sq. ft. °F/Btu		0.00006	0.00006	
Tube Plugging Level, %		0	10	
Zero Load Temperature, °F		557	557	

Table 1-2
NSSS PCWG Parameters for the MPS3 SPU Program

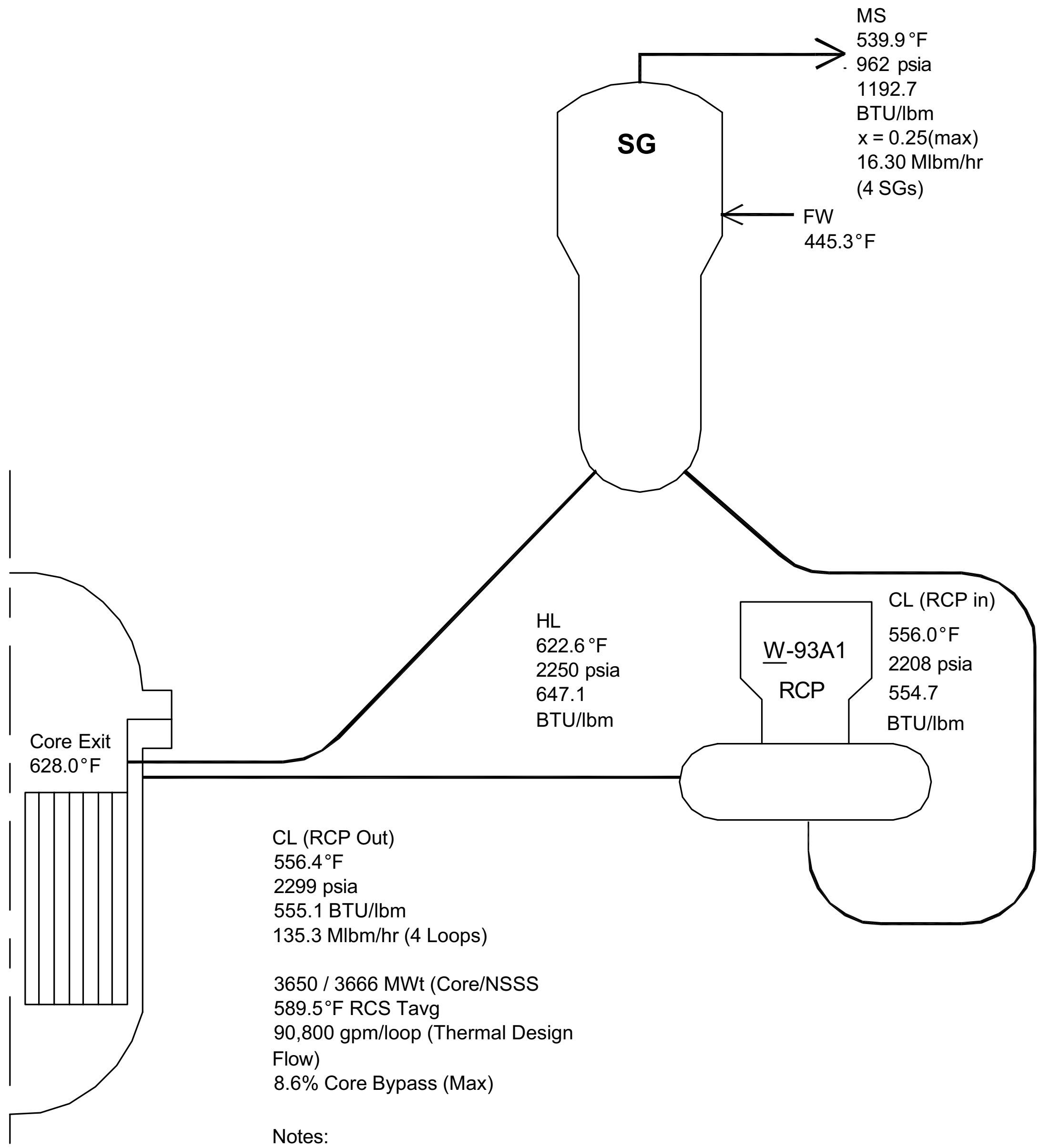
	SPU Program Lower Bound of T_{Avg} Range for DNB Transient Analyses and Associated Setpoint Use			
		Case 5	**Case 6**	
Hydraulic Design Parameters				
Pump Design Point, Flow (gpm)/Head (ft.)	100,400/289			
Mechanical Design Flow, gpm	103,600			
Minimum Measured Flow, gpm/total	379,200			

Footnotes:

a. Core bypass flow accounts for Thimble Plug Removal (TPR) and Intermediate Flow Mixing Vanes (IFMs).

b. If thimble plugs are installed, the core bypass flow is 6.6%, core outlet temperature is 619.3°F, and core average temperature is 585.6°F.

Figure 1-1 Heat Balance Diagram



Notes:

1. Numbers may not balance exactly due to rounding.
2. Actual RCS flow is substantially greater than TDF.

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material Surveillance Program

2.1.1.1 Regulatory Evaluation

The reactor vessel material surveillance program provides a means for determining and monitoring the fracture toughness of the RV belt line materials to support analyses for ensuring the structural integrity of the ferritic components of the RV. The DNC review primarily focused on the effects of the present and the proposed license extension RV surveillance capsule withdrawal schedule.

The acceptance criteria are based on:

- GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture.
- GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to ensure that, under specific conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized.
- 10 CFR 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the RV belt line region.
- 10 CFR 50.60, which requires compliance with the requirements of 10 CFR 50, Appendix H.

Specific review criteria are contained in SRP Section 5.3.1, and the guidance provided in Matrix 1 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants,
July 1981,(NUREG-0800), Section 5.3.1, Rev. 1.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria (GDC) for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to conformance to:

- GDC-14, Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.14.

  The RCS boundary is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits (see FSAR Section 3.9). RCS pressure boundary materials, selection, and fabrication techniques ensure a low probability of gross rupture or abnormal leakage.

In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions, such as seismic and pipe rupture, as discussed in FSAR Sections 3.6 and 3.7.

The RCS boundary has provisions for inspection, testing, and surveillance of critical areas to assess their structural and leak-tight integrity (see FSAR Section 5.2). For the RV (FSAR Section 5.3), a materials surveillance program conforming to applicable codes is provided.

- GDC-31, Fracture Prevention of Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.31.

Close control is maintained over material selection and fabrication for the RCS to assure that the boundary behaves in a non-brittle manner. The RCS materials exposed to the coolant are corrosion-resistant stainless steel or Inconel. The nil ductility reference temperature of the RV structural steel is established by Charpy V-notch and drop weight tests, in accordance with 10 CFR 50, Appendix G.

FSAR Section 3.1.2.31 states in part that, as part of the RV specification, certain requirements which are not specified by the applicable ASME Codes are performed as follows:

- A 100 percent volumetric ultrasonic test of reactor vessel plate for shear wave and a post-hydro test map of all full penetration ferritic pressure boundary welds in the pressure vessel are performed.
- Reactor vessel core region material chemistry (copper, phosphorus, and vanadium) is controlled to reduce sensitivity to embrittlement due to irradiation over the life of the plant.
- 10 CFR 50, Appendix H, Reactor Vessel Material Surveillance Program Requirements, is described in FSAR Sections 3.1.2.31 and 3.1.2.32, as follows:

A radiation surveillance program is provided. In this program, the evaluation of radiation damage is based on pre-irradiation and post-irradiation testing of Charpy V-notch and tensile specimens. These programs are directed toward evaluation of the effects of radiation on the fracture toughness of RV steels, based on the reference transition temperature approach and the fracture mechanics approach, and are in accordance with ASTM-E-185-82 and the requirements of 10 CFR 50, Appendix H.

Monitoring changes in the fracture toughness properties of the RV core region plates forging, weldments, and associated heat treated zones are performed in accordance with 10 CFR 50, Appendix H. Samples of RV plate materials are retained and catalogued in case future engineering development shows the needs for further testing.

The material properties surveillance program includes not only the conventional tensile and impact tests, but also the fracture mechanics specimens. The observed shifts in nil ductility reference temperature of the core region materials with irradiation are used to confirm the allowable limits calculated for all operational transients. FSAR Section 5.3.1.6 provides more details.

- 10 CFR 50.60, acceptance criteria for fracture prevention measures for lightwater nuclear power reactors for normal operation is described below.

  The provisions of 10 CFR 50.60 allow use of alternatives to the described requirements in 10 CFR 50, Appendices G and H, when an exemption is granted by the NRC under 10 CFR 50.12.

  DNC complies with the requirements of 10 CFR 50, Appendix H (except for one exception related to P-T limit curves used in the plant Technical Specifications during normal operating and hydrostatic or leak rate testing conditions—see Section 2.1.3). Therefore, the requirements of 10 CFR 50.60 are satisfied.

- NRC RG 1.190, Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence is described below:

  For license renewal, FSAR Section 19.3.1.3 states that Millstone Unit 3 will calculate USE, RT_{PTS} and P-T limits based on fluence values developed in accordance with RG 1.190 requirements, as amended or superseded by future regulatory guidance changes, through the period of extended operation.

2.1.1.2 Technical Evaluation

2.1.1.2.1 Introduction

Reactor vessel integrity is impacted by any change in plant parameters that affect neutron fluence levels or temperature/pressure transients. The changes in neutron fluence resulting from the SPU have been evaluated to determine the impact on reactor vessel integrity. The assessment presented herein focuses on the MPS3 surveillance capsule withdrawal schedule contained in the most recent surveillance capsule evaluation, WCAP-16629-NP (Reference 1). In this assessment, vessel fluence values are used to evaluate the transition temperature shift (RT_{NDT}) to confirm the validity of the surveillance capsule withdrawal schedule.

2.1.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

SPU Fluence Projections

Neutron fluence projections considering SPU conditions are presented in Tables 2.1.1-1 and 2.1.1-2 for the conventional beltline materials and extended beltline materials, respectively. Surveillance capsule fluence values are provided in Tables 2.1.1-3. Note that capsule fluence values listed in Tables 2.1.1-3 are not impacted by the SPU because the listed fluence values were determined only for capsules that have been removed from the vessel and thus are not subjected to additional neutron fluence.

The calculated fluence projections used in the SPU evaluation complied with RG 1.190. As these calculations were performed on a plant-by-plant basis, there was no generic topical report for the approved method. The methodology used was that of RG 1.190.

Inlet Temperature

As presented in Section 1.1, Nuclear Steam Supply System Parameters, the SPU full power reactor vessel inlet temperature range is 537.4°F to 556.4°F.

Chemistry Factor Values

The CFs, along with the FFs, are used to determine RT_{NDT}. Table 2.1.1-4 presents the CFs used in this evaluation in Table 2.1.1-4, along with the best-estimate copper and nickel chemistry used to calculate the CF values.

Transition Temperature Shift Values

The RT_{NDT} calculations for each of the plates and welds in the MPS3 beltline and extended beltline are presented in Table 2.1.1-5.

Acceptance Criteria

The acceptance criteria for performing material surveillance of the reactor vessel and for generating a withdrawal schedule are in 10 CFR 50, Appendix H, and ASTM E 185-82, Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels, E 706.

The acceptance criteria for the reactor vessel inlet temperature are provided in RG 1.99, Rev 2, Radiation Embrittlement of Reactor Vessel Materials, which states that: “The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement.” Thus the reactor vessel inlet temperature must be greater than 525°F and less than 590°F for the equations and methodology of RG 1.99, Rev. 2, to remain valid.

2.1.1.2.3 Description of Analyses and Evaluations

The reactor vessel surveillance capsule withdrawal schedule evaluation for the proposed MPS3 SPU includes a review of the reactor vessel inlet temperature to verify that it complies with RG 1.99, Rev. 2, and a review of the vessel fluence projections to determine if changes are required to the number of capsules withdrawn and/or the schedule for withdrawal. This evaluation is consistent with the recommended practices of ASTM E 185-82 and meets the requirements of 10 CFR 50, Appendix H.

A surveillance capsule withdrawal schedule was developed to periodically remove surveillance capsules from the reactor vessel in order to effectively monitor the condition of the reactor vessel materials under actual operating conditions. ASTM E 185-82 defines both the recommended number of surveillance capsules and the recommended withdrawal schedule, based on the predicted transition temperature shifts (RT_{NDT}) of the vessel material. The surveillance capsule withdrawal schedule is in terms of EFPY of plant operation with an original design life of 32 EFPY, as is the case for MPS3. Other factors considered in establishing the surveillance capsule withdrawal schedule were the maximum fluence values at the vessel surface and the approval of life extension to a design life of 54 EFPY.

The first surveillance capsule is usually scheduled early in the vessel life to verify the initial predictions of the surveillance material response to the actual radiation environment. It is generally removed when the predicted shift exceeds the expected scatter by a sufficient margin to be measurable. Normally, the capsule with the highest lead factor is withdrawn first. Early withdrawal also permits verification of the adequacy and conservatism of the reactor vessel P-T operating limits. The withdrawal schedule for the remaining surveillance capsules to be withdrawn was adjusted by the lead factor so that:

- The neutron fluence exposure of the second surveillance capsule corresponds to the original design life 32 EFPY fluence at the reactor vessel inner wall location.
- The exposure of the third surveillance capsule withdrawn exceeds the peak original design life (32 EFPY) vessel fluence, but does not exceed twice that value.

Per ASTM E 185-82, the four steps used for the development of a surveillance capsule withdrawal schedule are as follows:

- Estimate the peak vessel inside surface fluence at end of life and the corresponding transition temperature shift. This identifies the number of capsules required. Per RG 1.99, Rev. 2, the transition temperature shift (RT_{NDT}) is equal to the chemistry factor times the fluence factor. In the case of determining the number of capsules to be withdrawn, the peak vessel surface fluence is used to determine the fluence factor.
- Obtain the lead factor for each surveillance capsule relative to the peak beltline fluence.
- Calculate the EFPY for the capsule to reach the peak vessel end-of-life fluence at the inside surface. These are used to establish the withdrawal schedule for all but the first surveillance capsule.
- Schedule the surveillance capsule withdrawals at the nearest vessel refueling date.

A surveillance capsule withdrawal schedule was developed for the MPS3 reactor vessel and documented in WCAP-16629-NP (Reference 1). Updated fluence projections are utilized herein to evaluate the applicability of that withdrawal schedule for MPS3 in its licensing basis for the stretch power uprate.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Section 4.2.1.3 of NUREG-1838 states: “Millstone Unit 3 uses a fluence methodology in accordance with DG-1053, and the specific methodology applied to the calculation followed the guidance of RG 1.190. DG-1053 is the draft version of RG 1.190 and provides similar conservatism when calculating the reactor vessel fluence values. Therefore, for MPS3, the fluence values meet the guidelines of RG 1.190 and are acceptable to the staff.”

The fluence projections for SPU are lower than those provided in WCAP-16629-NP (Reference 1), which contains the most recently developed surveillance capsule withdrawal schedule. No changes are required to the withdrawal schedule presented in Reference 1, since it remains valid considering the SPU fluence projections.

2.1.1.2.4 Results

Reactor vessel fluence projections were generated for SPU conditions following the guidance of RG 1.190 (presented in Tables 2.1.1-1 and 2.1.1-2). Note that these SPU vessel fluence projections are lower than the vessel fluence projections documented in WCAP-16629-NP (Reference 1). Calculated neutron fluence values in Reference 1 represented a power uprate conservatively beginning at the onset of Cycle 11. Current neutron fluence projections are based on the core power uprate from 3411 MWt to 3650 MWt taking place at the onset of Cycle 13.

Chemistry factors for each of the beltline and extended beltline materials were determined in accordance with RG 1.99, Rev. 2, Positions 1.1 and 1.2, as presented in Table 2.1.1-4. Transition temperature shifts were then calculated for each of the beltline and extended beltline materials (vessel inside surface) to determine the appropriate surveillance capsule withdrawal schedule, see Table 2.1.1-5. The calculations were performed at 54 EFPY, and the maximum neutron exposure for the beltline and extended beltline materials were applied to all plates and welds in the beltline and extended beltline region, respectively. All transition temperature shifts were calculated to be less than 100°F; hence the minimum number of surveillance capsules to be withdrawn is three, in accordance with ASTM E 185-82. Per ASTM E 185-82, the withdrawal of a capsule is scheduled for the vessel refueling outage nearest to the calculated EFPY established for the particular surveillance capsule withdrawal.

The removal of capsules from the MPS3 reactor vessel has met the intent of ASTM E 185-82 for a 32 EFPY original design life. Under the new MPS3 design life of 54 EFPY, the projected EOL vessel surface fluence under the SPU program would be 2.70×10^{19} n/cm^2 (E > 1.0 MeV). The third capsule withdrawn from MPS3, Capsule W (see Table 2.1.1-3), also exceeds this projected fluence value for 54 EFPY; hence no additional capsules would need to be tested for compliance with 10 CFR 50, Appendix H, and ASTM E 185-82.

As presented in Section 1.1, Nuclear Steam Supply System Parameters, the reactor vessel inlet temperature is maintained above 525°F and below 590°F. Therefore, the equations and results remain valid without adjustments for temperature effects.

A withdrawal schedule exists in Reference 1 that meets the intent of ASTM E 185-82 and 10 CFR 50, Appendix H. Having this withdrawal schedule satisfies 10 CFR 50.60, GDC-14, GDC-31, and the SRP (see Section 5.3.1).

2.1.1.3 Conclusion

DNC has reviewed the evaluation of the effects of the proposed SPU on the reactor vessel surveillance withdrawal schedule and concludes that DNC has adequately addressed changes in neutron fluence and their effects on the schedule. DNC further concludes that the reactor vessel capsule withdrawal schedule is appropriate to ensure that the material surveillance program will continue to meet the requirements of 10 CFR 50, Appendix H, and 10 CFR 50.60, and will provide DNC with information to ensure continued compliance with GDC-14 and GDC-31 in this respect following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the reactor vessel material surveillance program.

2.1.1.4 References

1. WCAP-16629-NP, Analysis of Capsule W from the Dominion Nuclear Connecticut Millstone Unit 3 Reactor Vessel Radiation Surveillance Program, F. C. Gift, et al, September 2006.

Table 2.1.1-1 Calculated Maximum Neutron Exposure of the Reactor Vessel Beltline Materials at the Clad/Base Metal Interface

Operating Time [EFPY]	Azimuthal Location			
	0.0 Degrees	15.0 Degrees	30.0 Degrees	45.0 Degrees
	Neutron Fluence [n/cm^2, (E > 1.0 MeV)]			
13.8 (EOC 10)	4.53E+18	6.68E+18	7.55E+18	7.49E+18
15.1	4.91E+18	7.20E+18	8.20E+18	8.18E+18
16.6	5.26E+18	7.76E+18	8.88E+18	8.88E+18
18.1	5.68E+18	8.35E+18	9.59E+18	9.54E+18
19.5	6.11E+18	8.99E+18	1.04E+19	1.03E+19
25.0	7.71E+18	1.12E+19	1.29E+19	1.27E+19
32.0	9.77E+18	1.41E+19	1.63E+19	1.57E+19
36.0	1.10E+19	1.58E+19	1.82E+19	1.75E+19
40.0	1.22E+19	1.75E+19	2.02E+19	1.93E+19
48.0	1.46E+19	2.09E+19	2.40E+19	2.28E+19
54.0	1.64E+19	2.34E+19	2.70E+19	2.55E+19
60.0	1.82E+19	2.59E+19	2.99E+19	2.81E+19

Table 2.1.1-2 Calculated Neutron Exposure of the Reactor Vessel Beltline and Extended Beltline Materials at the Clad/Base Metal Interface

Azimuth [Deg.]	MPS3 Beltline and Extended Beltline Materials	Neutron Fluence [n/cm^2, E > 1.0 MeV]	
		54 EFPY	60 EFPY
0	Outlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Inlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Nozzle Shell Plates (B9804-1, B9804-2, B9804-3)	5.18E+17	5.78E+17
	Nozzle Shell 0 Degree Long. Weld (101-122)	5.18E+17	5.78E+17
	Int. Shell to Nozzle Shell Circ. Weld (103-121)	5.18E+17	5.78E+17
	Int. Shell Plates (B9805-1, B9805-2, B9805-3)	1.62E+19	1.82E+19
	Int. Shell 0 Degree Long. Weld (101-124)	1.62E+19	1.82E+19
	Lower Shell to Int. Shell Circ. Weld (101-171)	1.62E+19	1.82E+19
	Lower Shell Plates (B9820-1, B9820-2, B9820-3)	1.64E+19	1.82E+19
	Lower Shell 0 Degree Long. Weld (101-142)	1.64E+19	1.82E+19
	Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17	<1.0E+17
15	Outlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Inlet Nozzles and Nozzle Welds	1.10E+17	1.22E+17
	Nozzle Shell Plates (B9804-1, B9804-2, B9804-3)	7.37E+17	8.22E+17
	Int. Shell to Nozzle Shell Circ. Weld (103-121)	7.37E+17	8.22E+17
	Int. Shell Plates (B9805-1, B9805-2, B9805-3)	2.31E+19	2.56E+19
	Lower Shell to Int. Shell Circ. Weld (101-171)	2.31E+19	2.56E+19
	Lower Shell Plates (B9820-1, B9820-2, B9820-3)	2.34E+19	2.59E+19
	Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17	<1.0E+17
30	Outlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Inlet Nozzles and Nozzle Welds	1.27E+17	1.41E+17
	Nozzle Shell Plates (B9804-1, B9804-2, B9804-3)	8.51E+17	9.49E+17
	Nozzle Shell 30 Degree Long. Welds (101-122)	8.51E+17	9.49E+17
	Int. Shell to Nozzle Shell Circ. Weld (103-121)	8.51E+17	9.49E+17
	Int. Shell Plates (B9805-1, B9805-2, B9805-3)	2.66E+19	2.95E+19
	Int. Shell 30 Degree Long. Welds (101-124)	2.66E+19	2.95E+19
	Lower Shell to Int. Shell Circ. Weld (101-171)	2.66E+19	2.95E+19
	Lower Shell Plates (B9820-1, B9820-2, B9820-3)	2.70E+19	2.99E+19
	Lower Shell 30 Degree Long. Welds (101-142)	2.70E+19	2.99E+19
	Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17	<1.0E+17

Table 2.1.1-2 Calculated Neutron Exposure of the Reactor Vessel Beltline and Extended Beltline Materials at the Clad/Base Metal Interface

Azimuth [Deg.]	MPS3 Beltline and Extended Beltline Materials	Neutron Fluence [n/cm^2, E > 1.0 MeV] 54 EFPY	60 EFPY
45	Outlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Inlet Nozzles and Nozzle Welds	1.20E+17	1.33E+17
	Nozzle Shell Plates (B9804-1, B9804-2, B9804-3)	8.03E+17	8.93E+17
	Int. Shell to Nozzle Shell Circ. Weld (103-121)	8.03E+17	8.93E+17
	Int. Shell Plates (B9805-1, B9805-2, B9805-3)	2.52E+19	2.78E+19
	Lower Shell to Int. Shell Circ. Weld (101-171)	2.52E+19	2.78E+19
	Lower Shell Plates (B9820-1, B9820-2, B9820-3)	2.55E+19	2.81E+19
	Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17	<1.0E+17

Table 2.1.1-3 Recommended Surveillance Capsule Withdrawal Schedule

Capsule	Capsule Location	Lead Factor[(a)]	Withdrawal EFPY[(b)]	Fluence (n/cm^2)[(a)]
U	58.5°	4.06	1.34	4.00×10^{18}
X	238.5°	4.35	8.00	1.98×10^{19}
W	121.5°	4.22	13.80	3.16×10^{19}[(c)]
Z	301.5°	4.22	Standby [(d)]	In Reactor
Y	241.0°	3.98	Standby [(e)]	2.98×10^{19}
V	61.0°	3.98	Standby [(e)]	2.98×10^{19}

Notes:

a. Updated in Capsule W dosimetry analysis.

b. Effective Full Power Years (EFPY) from plant startup.

c. This fluence is greater than one-times and less than two-times the projected 32 EFPY vessel fluence.

d. This capsule should be withdrawn anytime after the end of the next cycle, but not to exceed 25.7 EFPY, which is when the fluence on the capsule would exceed two-times the projected 54 EFPY vessel fluence. See Note (e).

e. These capsules were withdrawn after 13.80 EFPY (end of cycle 10) and placed into storage. Once all capsules are removed, alternative fluence measuring capabilities must be in place.

Table 2.1.1-4 Summary of the MPS3 Beltline and Extended Beltline Material Properties and Chemistry Factors Based on RG 1.99, Rev. 2

Material	Wt. % Cu	Wt. % Ni	Position 1.1 CF	Position 2.1 CF
Intermediate Shell Plate B9805-1	0.05	0.63	31.0°F	26.7°F
Intermediate Shell Plate B9805-2	0.05	0.64	31.0°F	- - -
Intermediate Shell Plate B9805-3	0.05	0.65	31.0°F	- - -
Lower Shell Plate B9820-1	0.08	0.63	51.0°F	- - -
Lower Shell Plate B9820-2	0.07	0.60	44.0°F	- - -
Lower Shell Plate B9820-3	0.06	0.61	37.0°F	- - -
Beltline Region Weld Metal[a]	0.05	0.05	31.8°F	6.7°F
Nozzle Shell Plate B9804-1	0.05	0.62	31°F	- - -
Nozzle Shell Plate B9804-2	0.08	0.64	51°F	- - -
Nozzle Shell Plate B9804-3	0.05	0.65	31°F	- - -
Inlet Nozzle B9806-3	0.09	0.83	58°F	- - -
Inlet Nozzle B9806-4	0.09	0.82	58°F	- - -
Inlet Nozzle R5-3	0.07	0.80	44°F	- - -
Inlet Nozzle R5-4	0.08	0.81	51°F	- - -
Nozzle Shell Longitudinal Weld 101-122A	0.05	0.12	39.8°F	- - -
Nozzle Shell Longitudinal Weld 101-122B, 101-122C	0.05	0.12	39.8°F	- - -
Nozzle Shell to Intermediate Shell Girth Weld 103-121	0.05	0.13	41°F	- - -
Inlet Nozzle Weld 105-121A	0.09	0.05	45.3°F	- - -
Inlet Nozzle Weld 105-121B	0.16	0.06	75.4°F	- - -
Inlet Nozzle Weld 105-121C	0.16	0.06	75.4°F	- - -
Inlet Nozzle Weld 105-121D	0.16	0.06	75.4°F	- - -

Notes:

a. MPS3 beltline welds were all fabricated using the same weld heat - #4P6052, flux type - Linde 0091, and flux lot number - 0145. The beltline welds include the intermediate to lower shell girth weld seam and the longitudinal weld seams in the intermediate shell course and lower shell course.

Table 2.1.1-5 ΔRT_{NDT} Values for all MPS3 Materials at 54 EFPY

Material	RG 1.99 R2 Method	CF (°F)	Fluence ($x10^{19} n/cm^2$)	FF[(a)]	ΔRT_{NDT}[(b)] (°F)
Intermediate Shell Plate B9805-1	Position 1.1	31.0	2.70	1.265	39.22
	Position 2.1	26.7	2.70	1.265	33.77
Intermediate Shell Plate B9805-2	Position 1.1	31.0	2.70	1.265	39.22
Intermediate Shell Plate B9805-3	Position 1.1	31.0	2.70	1.265	39.22
Lower Shell Plate B9820-1	Position 1.1	51.0	2.70	1.265	64.53
Lower Shell Plate B9820-2	Position 1.1	44.0	2.70	1.265	55.67
Lower Shell Plate B9820-3	Position 1.1	37.0	2.70	1.265	46.81
Intermediate Shell Longitudinal Weld Seams 101-124 A,B,C	Position 1.1	31.8	2.70	1.265	40.23
	Position 2.1	6.7	2.70	1.265	8.43
Intermediate to Lower Shell Girth Weld Seam 101-171	Position 1.1	31.8	2.70	1.265	40.23
	Position 2.1	6.7	2.70	1.265	8.43
Lower Shell Longitudinal Weld Seams 101-142 A,B,C	Position 1.1	31.8	2.70	1.265	40.23
	Position 2.1	6.7	2.70	1.265	8.43
Nozzle Shell Plate B9804-1	Position 1.1	31	0.0851	0.3854	11.95
Nozzle Shell Plate B9804-2	Position 1.1	51	0.0851	0.3854	19.65
Nozzle Shell Plate B9804-3	Position 1.1	31	0.0851	0.3854	11.95
Inlet Nozzle B9806-3	Position 1.1	58	0.0851	0.3854	22.35
Inlet Nozzle B9806-4	Position 1.1	58	0.0851	0.3854	22.35
Inlet Nozzle R5-3	Position 1.1	44	0.0851	0.3854	16.96
Inlet Nozzle R5-4	Position 1.1	51	0.0851	0.3854	19.65
Nozzle Shell Longitudinal Weld 101-122A	Position 1.1	39.8	0.0851	0.3854	15.34
Nozzle Shell Longitudinal Welds 101-122B, 101-122C	Position 1.1	39.8	0.0851	0.3854	15.34
Nozzle Shell to Intermediate Shell Girth Weld 103-121	Position 1.1	41	0.0851	0.3854	15.80
Inlet Nozzle Weld 105-121A	Position 1.1	45.3	0.0851	0.3854	17.46
Inlet Nozzle Weld 105-121B	Position 1.1	75.4	0.0851	0.3854	29.06

Table 2.1.1-5 ΔRT_{NDT} Values for all MPS3 Materials at 54 EFPY

Material	RG 1.99 R2 Method	CF (°F)	Fluence ($x10^{19} n/cm^2$)	FF[(a)]	ΔRT_{NDT}[(b)] (°F)
Inlet Nozzle Weld 105-121C	Position 1.1	75.4	0.0851	0.3854	29.06
Inlet Nozzle Weld 105-121D	Position 1.1	75.4	0.0851	0.3854	29.06

Notes:

a. FF = fluence factor = $f^{(0.28 - 0.1 \log (f))}$

b. ΔRT_{NDT} = CF * FF

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

2.1.2.1 Regulatory Evaluation

Pressure-temperature (P-T) limits are established to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including anticipated operation occurrences and hydrostatic tests. DNC's review of P-T limits covered the P-T limits methodology and the calculations for the number of EFPY specified for the SPU and the plant life extension addressed in NUREG-1838, considering neutron embrittlement effects and using linear elastic fracture mechanics.

The acceptance criteria are based on

- GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture.
- GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specific conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized.
- 10 CFR 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB.
- 10 CFR 50.60, which requires compliance with the requirements of 10 CFR 50, Appendix G.

Specific review criteria are contained in the SRP, Section 5.3.2 and the guidance provided in Matrix 1 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800), Section 5.3.2, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to conformance to

- GDC-14, Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.14.

  The RCS boundary is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits (see FSAR Section 3.9). RCS pressure boundary materials, selection, and fabrication techniques ensure a low probability of gross rupture or abnormal leakage.

  In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions, such as seismic and pipe rupture, as discussed in FSAR Sections 3.6 and 3.7.

The RCS boundary has provisions for inspection, testing, and surveillance of critical areas to assess their structural and leak-tight integrity (see FSAR Section 5.2). For the RV (FSAR Section 5.3), a materials surveillance program conforming to applicable codes is provided.

- GDC-31, Fracture Prevention of Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.31.

  Close control is maintained over material selection and fabrication for the RCS to assure that the boundary behaves in a non-brittle manner. The RCS materials exposed to the coolant are corrosion-resistant stainless steel or Inconel. The nil ductility reference temperature of the RV structural steel is established by Charpy V-notch and drop weight tests, in accordance with 10 CFR 50, Appendix G.

  Allowable pressure-temperature relationships for plant heatup and cooldown rates are calculated using methods derived from the ASME Code, Section III, Appendix G, Protection Against Non-Ductile Failure. This approach specifies that allowed stress intensity factors for all vessel operating conditions may not exceed the referenced stress intensity factor (KIR) for the metal temperature at any time. Operating specifications include conservative margins for predicted changes in the material reference temperature due to irradiation.

  FSAR Section 5.3.2 describes how controlling P-T limits during plant operation is a means to ensure vessel integrity throughout the life of the RV.

- 10 CFR 50, Appendix G, Fracture Toughness Requirements, is described in FSAR Section 19.3.1.1 as follows:

  FSAR Section 19.3.1.1 states in part that 10 CFR 50, Appendix G, contains screening criteria that establish limits on how far the upper-shelf energy values for a reactor pressure vessel material may be allowed to drop due to neutron irradiation exposure. The regulation requires the initial upper-shelf energy value to be greater than 75 ft-lb in the unirradiated condition and for the value to be greater than 50 ft-lb in the fully irradiated condition, as determined by Charpy V-notch specimen testing through the licensed life of the plant. Upper-shelf energy values of less than 50 ft-lb may be acceptable to the NRC if it can be demonstrated to the NRC that these lower values will provide margins of safety against brittle fracture equivalent to those required by ASME Section XI, Appendix G.

  FSAR Section 5.3.2.1 states in part that the operational curves (P-T limits) have been established for the ferritic materials of the RCS, considering ASME B&PV Code Section XI, Appendix G, as modified by ASME Code Case N-640, and the additional requirements of 10 CFR 50, Appendix G. The FSAR also states in part that implementation of these specific requirements provide adequate margin to brittle fracture of ferritic materials during normal operation, anticipated operational occurrences, and system leak and hydrostatic tests.

- 10 CFR 50.60, Acceptance criteria for fracture prevention measures for lightwater nuclear power reactors for normal operation.

  The provisions of 10 CFR 50.60 allow use of alternatives to the described requirements in Appendices G and H of 10 CFR 50, when an exemption is granted by the NRC under 10 CFR 50.12.

In a letter dated April 23, 2001, DNC requested an exemption from the NRC from specific requirements of 10 CFR 50, Appendix G, to allow use of ASME B&PV Code Section XI, Code Case N-640, Alternative Reference Fracture Toughness for Development of Pressure-Temperature (P-T) Limit Curves for ASME Section XI, Division 1, for MPS3. The exemption addresses P-T limit curves used in the plant Technical Specifications during normal operating and hydrostatic or leak-rate testing conditions. In a letter dated August 14, 2001, the NRC granted the exemption discussed above, pursuant to 10 CFR 50.12.

DNC complies with the requirements of 10 CFR 50, Appendix G, (except as noted above). Therefore, the requirements of 10 CFR 50.60 are satisfied.

- NRC RG 1.99, Radiation Embrittlement of Reactor Vessel Materials.

  Section B 3/4.4.9 of the Technical Specification Bases, Pressure/Temperature Limits, states in part that MPS3 currently addresses P-T limit curves as follows:

- The actual shift in RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated RV material specimens, in accordance with ASTM E 185-82 and 10 CFR 50, Appendix H.

- The operating P-T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of NRC RG 1.99.

  FSAR Section 19.3.1.1 states in part that acceptable upper-shelf energy values have been calculated in accordance with RG 1.99, Rev. 2, to the end of the period of extended operation. Calculated upper-shelf energy values for the most limiting RVP beltline plate and weld materials remain greater than 50 ft-lb.

- NRC RG 1.190, Calculation of Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.

  For license renewal, FSAR Section 19.3.1.3 states in part that, in accordance with 10 CFR 50, Appendix G, updated pressure-temperature limits for entering the period of extended operation will be developed and implemented prior to the period of extended power operation. Cold overpressure protection system temperature requirements will be updated to ensure that the pressure-temperature limits will not be exceeded for postulated plant transients during the period of extended operation. Millstone Unit 3 will calculate USE, RT_{PTS} and P-T limits based on fluence values developed in accordance with RG 1.190 requirements, as amended or superseded by future regulatory guidance changes, through the period of extended operation.

2.1.2.2 Technical Evaluation

2.1.2.2.1 Introduction

Reactor vessel integrity is impacted by any change in plant parameters that affect neutron fluence levels or temperature/pressure transients. The changes in neutron fluence resulting from the SPU have been evaluated to determine the impact on reactor vessel integrity. The assessment presented herein focuses on the MPS3 P-T limits at 32 EFPY (relative to adjusted reference temperature calculations in Reference 1) and the projected values of upper-shelf energy at 54 EFPY. In this section, 32 EFPY vessel surface fluence values under SPU conditions are compared with those used to determine the 32 EFPY adjusted reference temperatures (RT_{NDT}) in Reference 1 for development of the MPS3 P-T limits. The projected decrease in USE due to irradiation embrittlement based on uprated fluence values is evaluated to ensure adequate margin in USE at 54 EFPY.

2.1.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Definition of Reactor Vessel Beltline Materials

The beltline region of the reactor vessel is defined in 10 CFR 50, Appendix G, as the material (including welds, heat-affected zone, and plates or forgings) that directly surround the effective height of the active core and adjacent regions of the reactor vessel that are predicted to experience sufficient neutron radiation damage to be considered in the selection of the most limiting material with regard to radiation damage. By convention, the beltline materials evaluated have been limited to those that envelope the axial height of the active core. Traditionally-defined beltline materials have been extended to include all reactor vessel plates and welds that exceed $1x10^{17}$ n/cm^2 (E > 1.0 MeV) at the end of licensed plant operation. These additional plates and welds are appropriately called the “extended beltline” materials.

SPU Fluence Projections

Neutron fluence projections considering SPU conditions are presented in Tables 2.1.2-1 and 2.1.2-2 for the conventional beltline materials and extended beltline materials, respectively. These calculations were performed on a plant-by-plant basis, there was no generic topical report for the approved method. The methodology used was that of RG 1.190.

Inlet Temperature

As presented in Section 1.1, Nuclear Steam Supply System Parameters, the SPU full power reactor vessel inlet temperature range is 537.4°F to 556.4°F.

Chemistry

Chemistry of the plates and welds, specifically the weight percent copper, was used along with neutron fluence to determine the predicted decrease in USE at the end-of-life extension. The weight percent copper for all the beltline and extended beltline materials is presented in Table 2.1.2-3.

Upper-Shelf Energy

The initial USE values for each plate and weld in the conventional/extended beltline are used to determine the projected USE values at 54 EFPY. Extended beltline materials are evaluated at 54 EFPY only. These initial USE values are presented in Table 2.1.2-3.

Pressure-Temperature Limits

The P-T limit curves are presently contained in the Technical Specifications, Section 3/4.4.9 as determined for a 32 EFPY end-of-life, for a projected neutron fluence of $1.97x10^{19}$ n/cm^2.

Reactor vessel integrity evaluations, provided in Reference 1, form the basis for adjusted Reference Temperature Values of the Technical Specification P-T limits.

Acceptance Criteria

For P-T limit curves, the acceptance criteria are that MPS3 have NRC-approved P-T limits developed in accordance with 10 CFR 50, Appendix G, and that the applicable EFPY of those P-T limit curves after implementation of the SPU do not invalidate the term of applicability.

For USE at SPU conditions, 54 EFPY values for all reactor beltline materials must meet the requirements of 10 CFR 50, Appendix G, which states the USE must be maintained above 50 ft-lb; otherwise an equivalent margins analysis must be performed to demonstrate that the vessel has adequate margin of safety.

The acceptance criteria for the reactor vessel inlet temperature are provided in U.S. NRC RG 1.99, Rev. 2, Radiation Embrittlement of Reactor Vessel Materials, which states that “The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement.” Thus the reactor vessel inlet temperature must be greater than 525°F and less than 590°F for the equations and methodology of RG 1.99, Rev. 2, to remain valid.

2.1.2.2.3 Description of Analyses and Evaluations

If the post-SPU reactor vessel fluence projection at 32 EFPY exceeds that of the analysis of record, then a new applicability date of the current P-T limit curves would need to be calculated. This would be a simple interpolation using the SPU fluence projections in Table 2.1.2-1. If the post-SPU reactor vessel fluence projection is lower than the 32 EFPY neutron fluence value utilized in the analysis of record, then conservatively, no change to the applicability date is required. MPS3 would be required to calculate new P-T Limit Curves prior to continuing operation into the life-extension period.

The evaluation to assess the impact of the SPU on USE requires that the percentage decrease in USE be determined in accordance with RG 1.99, Rev. 2, for each plate and weld in the vessel beltline and extended beltline. Percentage decreases in USE, from the initial unirradiated USE, can be predicted as a function of neutron fluence for plates and welds of known copper content. Fluence values used to determine USE decreases are those at the 1/4 vessel thickness, using the fluence attenuation formula provided in RG 1.99, Rev. 2. Values for USE at 54 EFPY are then evaluated against the acceptance criteria of 50 ft-lb in 10 CFR 50, Appendix G.

Evaluation of the proposed MPS3 SPU also includes a review of the reactor vessel inlet temperature to verify that it complies with RG 1.99, Rev. 2, which provides the embrittlement correlations used to calculate changes to adjusted reference temperature (for determination of P-T Limit Curves) and upper-shelf energy as a function of neutron fluence.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Section 4.2.1.3 of NUREG-1838 states: “Millstone Unit 3 uses a fluence methodology in accordance with DG-1053, and the specific methodology applied to the calculation followed the guidance of RG 1.190. DG-1053 is the draft version of RG 1.190 and provides similar conservatism when calculating the reactor vessel fluence values. Therefore, for Millstone Unit 3, the fluence values meet the guidelines of RG 1.190 and are acceptable to the staff."

DNC has evaluated the impact of the SPU on the conclusions for USE of the MPS3 beltline materials reached in the license renewal application. Updated neutron fluence projections accounting for the SPU are lower in magnitude than the projections of fluence used in the license renewal application for calculating USE of the beltline materials at 54 EFPY. The license renewal application used a 1/4-T fluence of 1.97×10^{19} n/cm^2 (see Table 4.2-1 of the MPS3 License Renewal Application) in its USE projection calculations for MPS3 beltline materials at 54 EFPY and demonstrated a satisfactory margin above 50 ft-lb. The updated 1/4-T fluence value of 1.609×10^{19} n/cm^2 was used in the current 54 EFPY calculations of beltline material USE, as provided in Table 2.1.2-4, and does not impact the USE results previously determined using the higher neutron fluence.

2.1.2.2.4 Results

Reactor vessel fluence projections were generated for SPU conditions following the guidance of RG 1.190 (see Tables 2.1.2-1 and 2.1.2-2).

At 32 EFPY, the maximum projected fluence on the MPS3 reactor vessel beltline, accounting for SPU conditions, would be 1.63×10^{19} n/cm^2 (E > 1.0 MeV). MPS3 has developed pressure-temperature limit curves applicable to 32 EFPY based on a neutron fluence of 1.97×10^{19} n/cm^2, which is more than 20 percent higher than the current predictions for 32 EFPY. The Initial RT_{NDT} and chemistry factor for the limiting material is unchanged as a result of the SPU. Adjusted reference temperature values calculated with a lower fluence considering SPU conditions would, therefore, be correspondingly lower in magnitude; hence, no changes to the date of applicability for the P-T limit curves are required.

Neutron fluence values at 54 EFPY for the 1/4T vessel thickness location were used to predict the decrease in USE for materials in the MPS3 reactor vessel. Table 2.1.2-3 provides the copper chemistry and initial USE of the beltline and extended beltline materials. The copper chemistry and 1/4T fluence were used in accordance with RG 1.99, Rev. 2, to predict the percentage decrease in USE at 54 EFPY. The USE predictions are provided in Table 2.1.2-4, which demonstrates that all plates and welds are all predicted to have USE values that remain above 50 ft-lb.

As presented in Section 1.1, Nuclear Steam Supply System Parameters, the reactor vessel inlet temperature is maintained above 525°F and below 590°F. Therefore, the equations and results remain valid without adjustments for temperature effects.

An NRC-approved set of P-T limit curves exists in the Technical Specifications Section B 3/4.4.9, which satisfies the requirements of 10 CFR 50, Appendix G, for a 32 EFPY term of applicability, with consideration of the SPU neutron fluence exposure. Additionally, the SPU fluence projections were shown not to reduce the level of USE for any plate or weld in the beltline and extended beltline to below 50 ft-lb at 54 EFPY in accordance with 10 CFR 50, Appendix G.

DNC has evaluated the impact of the SPU on the current P-T limits and projected USE for beltline and extended beltline materials in the MPS3 vessel. The 32 EFPY pressure-temperature limits in the analysis of record are conservative with respect to the projected fluence used as the basis for their development, relative to the updated fluence exposure calculated for SPU conditions; such that no change to the term of applicability is required. All plates and welds in the MPS3 beltline and extended beltline have projected values for USE above 50 ft-lb at 54 EFPY.

2.1.2.3 Conclusion

DNC has reviewed the evaluation of the effects of the proposed SPU on the P-T limits for MPS3 and concludes that the evaluation has adequately addressed changes in neutron fluence and their effects on the P-T limits. DNC further concludes that the evaluation has demonstrated the validity of the current P-T limits for operation under the proposed SPU conditions. Based on this, DNC concludes that the current P-T limits will continue to meet the requirements of 10 CFR 50, Appendix G, and 10 CFR 50.60 and will enable MPS3 to comply with GDC-14 and GDC-31 in this respect following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the current P-T limits.

2.1.2.4 References

1. 95-SDS-1008MG, Rev. 5, Calculation of Adjusted Reference Temperatures for the MP2 and MP3 Reactor Vessels, May 2005.

2. WCAP-10732, Northeast Utilities Service Company Millstone Unit No. 3 Reactor Vessel Radiation Surveillance Program, L. R. Singer, June 1985.

3. WCAP-16629-NP, Analysis of Capsule W from the Dominion Nuclear Connecticut Millstone Unit 3 Reactor Vessel Radiation Surveillance Program, F. C. Gift, et al, September 2006.

Table 2.1.2-1 Calculated Maximum Neutron Exposure of the Reactor Vessel Beltline Materials at the Clad/Base Metal Interface

Operating Time [EFPY]	Azimuthal Location			
	0.0 Degrees	15.0 Degrees	30.0 Degrees	45.0 Degrees
	Neutron Fluence [n/cm^2, (E > 1.0 MeV)]			
13.8 (EOC 10)	4.53E+18	6.68E+18	7.55E+18	7.49E+18
15.1	4.91E+18	7.20E+18	8.20E+18	8.18E+18
16.6	5.26E+18	7.76E+18	8.88E+18	8.88E+18
18.1	5.68E+18	8.35E+18	9.59E+18	9.54E+18
19.5	6.11E+18	8.99E+18	1.04E+19	1.03E+19
25.0	7.71E+18	1.12E+19	1.29E+19	1.27E+19
32.0	9.77E+18	1.41E+19	1.63E+19	1.57E+19
36.0	1.10E+19	1.58E+19	1.82E+19	1.75E+19
40.0	1.22E+19	1.75E+19	2.02E+19	1.93E+19
48.0	1.46E+19	2.09E+19	2.40E+19	2.28E+19
54.0	1.64E+19	2.34E+19	2.70E+19	2.55E+19
60.0	1.82E+19	2.59E+19	2.99E+19	2.81E+19

Table 2.1.2-2 Calculated Neutron Exposure of the Reactor Vessel Beltline and Extended Beltline Materials at the Clad/Base Metal Interface

Azimuth [Deg.]	MPS3 Beltline and Extended Beltline Materials	Neutron Fluence [n/cm^2, E > 1.0 MeV] 54 EFPY	Neutron Fluence [n/cm^2, E > 1.0 MeV] 60 EFPY
0	Outlet Nozzles and Nozzle Welds Inlet Nozzles and Nozzle Welds Nozzle Shell Plates (B9804-1, B9804-2, B9804-3) Nozzle Shell 0 Degree Long. Weld (101-122) Int. Shell to Nozzle Shell Circ. Weld (103-121) Int. Shell Plates (B9805-1, B9805-2, B9805-3) Int. Shell 0 Degree Long. Weld (101-124) Lower Shell to Int. Shell Circ. Weld (101-171) Lower Shell Plates (B9820-1, B9820-2, B9820-3) Lower Shell 0 Degree Long. Weld (101-142) Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17 <1.0E+17 5.18E+17 5.18E+17 5.18E+17 1.62E+19 1.62E+19 1.62E+19 1.64E+19 1.64E+19 <1.0E+17	<1.0E+17 <1.0E+17 5.78E+17 5.78E+17 5.78E+17 1.82E+19 1.82E+19 1.82E+19 1.82E+19 1.82E+19 <1.0E+17
15	Outlet Nozzles and Nozzle Welds Inlet Nozzles and Nozzle Welds Nozzle Shell Plates (B9804-1, B9804-2, B9804-3) Int. Shell to Nozzle Shell Circ. Weld (103-121) Int. Shell Plates (B9805-1, B9805-2, B9805-3) Lower Shell to Int. Shell Circ. Weld (101-171) Lower Shell Plates (B9820-1, B9820-2, B9820-3) Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17 1.10E+17 7.37E+17 7.37E+17 2.31E+19 2.31E+19 2.34E+19 <1.0E+17	<1.0E+17 1.22E+17 8.22E+17 8.22E+17 2.56E+19 2.56E+19 2.59E+19 <1.0E+17
30	Outlet Nozzles and Nozzle Welds Inlet Nozzles and Nozzle Welds Nozzle Shell Plates (B9804-1, B9804-2, B9804-3) Nozzle Shell 30 Degree Long. Welds (101-122) Int. Shell to Nozzle Shell Circ. Weld (103-121) Int. Shell Plates (B9805-1, B9805-2, B9805-3) Int. Shell 30 Degree Long. Welds (101-124) Lower Shell to Int. Shell Circ. Weld (101-171) Lower Shell Plates (B9820-1, B9820-2, B9820-3) Lower Shell 30 Degree Long. Welds (101-142) Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17 1.27E+17 8.51E+17 8.51E+17 8.51E+17 2.66E+19 2.66E+19 2.66E+19 2.70E+19 2.70E+19 <1.0E+17	<1.0E+17 1.41E+17 9.49E+17 9.49E+17 9.49E+17 2.95E+19 2.95E+19 2.95E+19 2.99E+19 2.99E+19 <1.0E+17

Table 2.1.2-2 Calculated Neutron Exposure of the Reactor Vessel Beltline and Extended Beltline Materials at the Clad/Base Metal Interface

Azimuth [Deg.]	MPS3 Beltline and Extended Beltline Materials	Neutron Fluence [n/cm^2, E > 1.0 MeV]	
		54 EFPY	60 EFPY
45	Outlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Inlet Nozzles and Nozzle Welds	1.20E+17	1.33E+17
	Nozzle Shell Plates (B9804-1, B9804-2, B9804-3)	8.03E+17	8.93E+17
	Int. Shell to Nozzle Shell Circ. Weld (103-121)	8.03E+17	8.93E+17
	Int. Shell Plates (B9805-1, B9805-2, B9805-3)	2.52E+19	2.78E+19
	Lower Shell to Int. Shell Circ. Weld (101-171)	2.52E+19	2.78E+19
	Lower Shell Plates (B9820-1, B9820-2, B9820-3)	2.55E+19	2.81E+19
	Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17	<1.0E+17

Table 2.1.2-3 MPS3 Beltline and Extended Beltline Region Materials Properties

Material	Wt % Cu	Unirradiated USE (ft-lb)
Intermediate Shell Plate B9805-1	0.05	93 (a)
Intermediate Shell Plate B9805-2	0.05	90
Intermediate Shell Plate B9805-3	0.05	107
Lower Shell Plate B9820-1	0.08	77
Lower Shell Plate B9820-2	0.07	76
Lower Shell Plate B9820-3	0.06	80
Inter. Shell Longitudinal Weld Seams 101-124 A,B,C	0.05	200 (a)
Intermediate to Lower Shell Girth Weld Seam 101-171	0.05	200 (a)
Lower Shell Longitudinal Weld Seams 101-142 A,B,C	0.05	200 (a)
Nozzle Shell Plate B9804-1	0.05	85.5
Nozzle Shell Plate B9804-2	0.08	104
Nozzle Shell Plate B9804-3	0.05	103
Inlet Nozzle B9806-3	0.09	162
Inlet Nozzle B9806-4	0.09	158
Inlet Nozzle R5-3	0.07	130
Inlet Nozzle R5-4	0.08	136
Nozzle Shell Longitudinal Weld 101-122A	0.05	>101
Nozzle Shell Longitudinal Welds 101-122B, 101-122C	0.05	>123
Nozzle Shell to Intermediate Shell Girth Weld 103-121	0.05	132
Inlet Nozzle Weld 105-121A	0.09	>89
Inlet Nozzle Weld 105-121B	0.16	177
Inlet Nozzle Weld 105-121C	0.16	>89

Table 2.1.2-3 MPS3 Beltline and Extended Beltline Region Materials Properties

Material	Wt % Cu	Unirradiated USE (ft-lb)
Inlet Nozzle Weld 105-121D	0.16	147

Notes:

a. The original published source of the unirradiated USE for the vessel materials is Appendix A of WCAP-10732, (Reference 2). ASTM E185 provides guidance for defining the upper-shelf energy region of the Charpy transition curve and quantifying the values of upper-shelf energy for a material. Vessel material toughness properties were determined through separate Charpy V-Notch tests than those used to provide upper-shelf energy values for surveillance materials, for which the test data was provided directly in Reference 2. ASTM E185 calculations of USE for these two vessel materials (Plate B9805-1 and Weld Heat - #4P6052, Flux Type Linde 0091, and Flux Lot Number 0145) utilized Charpy V-Notch test data from the material supplier (plate forgings) and CE Power Systems (weld deposit) to obtain the values provided in WCAP-10732 for vessel materials, as identified in this table.

   Millstone previously provided the NRC with upper-shelf energy values of 113.3 ft-lb and 144 ft-lb, respectively, for the vessel plate B9805-1 and vessel weld metal. These upper-shelf energy values were based on determination of upper-shelf energy using Charpy V-notch tests of the surveillance materials. These USE values were determined by averaging the three highest temperature points (at > 100 percent shear) of Charpy V-Notch test data (impact energy) for the weld metal (Heat 4P6052) and transverse orientation plate (B9805-1) surveillance specimen test results.

Table 2.1.2-4 USE Prediction Calculations at 54 EFPY for the MPS3 Beltline and Extended Beltline Region Materials

Material	1/4T Fluence[(a)] (10^{19} n/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected USE (ft-lb)
Intermediate Shell Plate B9805-1	1.609	93	6.0 [(b)]	87.4
Intermediate Shell Plate B9805-2	1.609	90	21 [(c)]	71.1
Intermediate Shell Plate B9805-3	1.609	107	21 [(c)]	84.5
Lower Shell Plate B9820-1	1.609	77	21 [(c)]	60.8
Lower Shell Plate B9820-2	1.609	76	21 [(c)]	60.0
Lower Shell Plate B9820-3	1.609	80	21 [(c)]	63.2
Inter. Shell Longitudinal Weld Seams 101-124 A,B,C	1.609	200	8.4 [(b)]	183.2
Intermediate to Lower Shell Girth Weld Seam 101-171	1.609	200	8.4 [(b)]	183.2
Lower Shell Longitudinal Weld Seams 101-142 A,B,C	1.609	200	8.4 [(b)]	183.2
Nozzle Shell Plate B9804-1	0.05072	85.5	9.3 [(c)]	77.5
Nozzle Shell Plate B9804-2	0.05072	104	9.3 [(c)]	94.3
Nozzle Shell Plate B9804-3	0.05072	103	9.3 [(c)]	93.4
Inlet Nozzle B9806-3	0.05072	162	9.3 [(c)]	146.9
Inlet Nozzle B9806-4	0.05072	158	9.3 [(c)]	143.3
Inlet Nozzle R5-3	0.05072	130	9.3 [(c)]	117.9
Inlet Nozzle R5-4	0.05072	136	9.3 [(c)]	123.4
Nozzle Shell Longitudinal Weld 101-122A	0.05072	>101	9.3	91.6
Nozzle Shell Longitudinal Welds 101-122B, 101-122C	0.05072	>123	9.3	111.6
Nozzle Shell to Intermediate Shell Girth Weld 103-121	0.05072	132	9.3	119.7
Inlet Nozzle Weld 105-121A	0.05072	>89	11.5	78.8

Table 2.1.2-4 USE Prediction Calculations at 54 EFPY for the MPS3 Beltline and Extended Beltline Region Materials

Material	1/4T Fluence[(a)] (10^{19} n/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected USE (ft-lb)
Inlet Nozzle Weld 105-121B	0.05072	177	15	150.5
Inlet Nozzle Weld 105-121C	0.05072	>89	15	75.7
Inlet Nozzle Weld 105-121D	0.05072	147	15	125.0

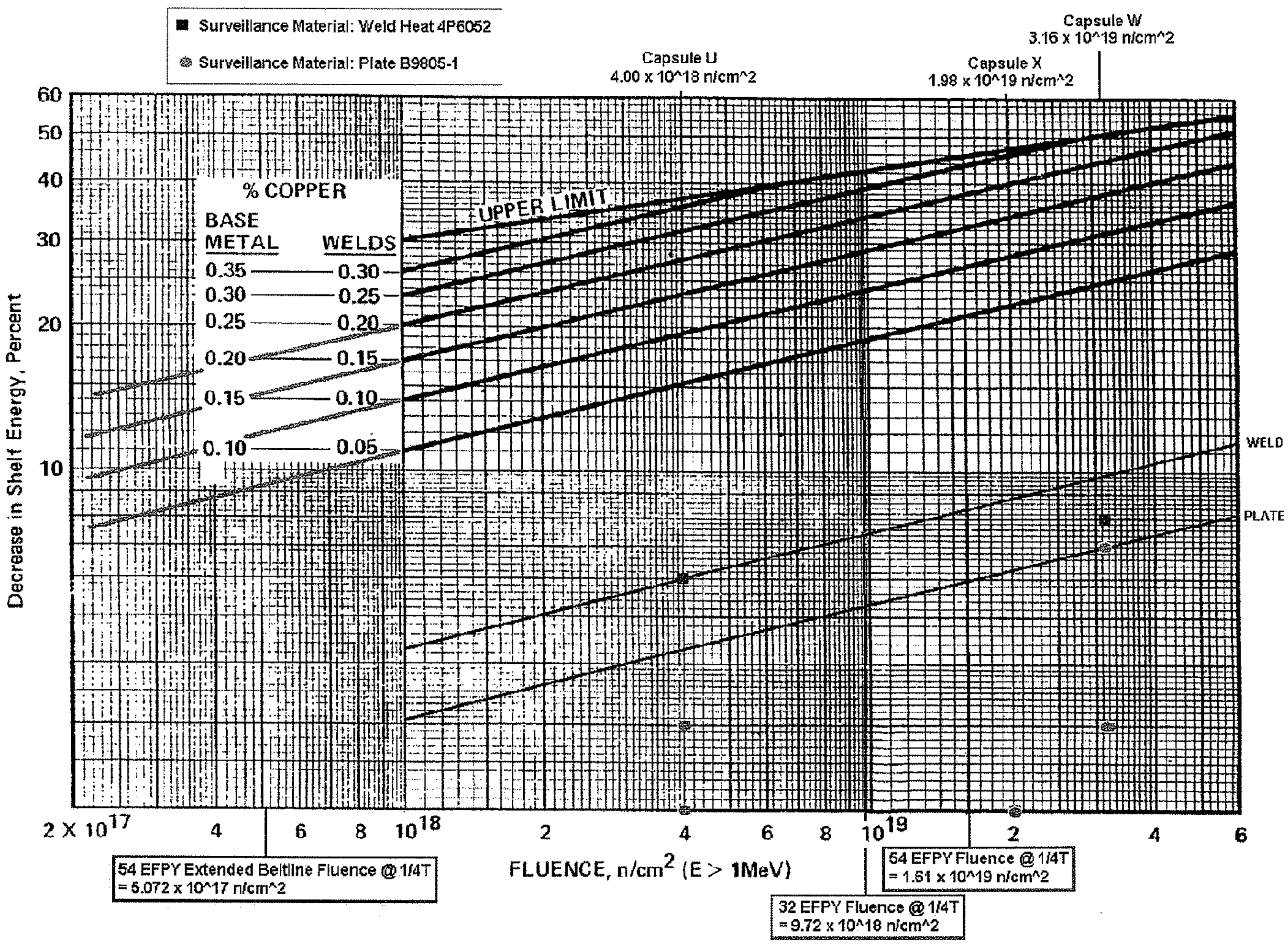
Notes:

a. Maximum vessel surface fluence at 54 EFPY used (2.70x10^{19} n/cm^2, E>1.0 MeV for the beltline materials and 8.51x10^{17} n/cm^2, E>1.0 MeV for the extended beltline materials).

b. Percentage USE Decrease is based on Position 2.2 of RG 1.99, Rev. 2, using data from the most recent surveillance capsule analysis (see Reference 3). Position B Credibility Criterion 3 in RG 1.99, Rev. 2, indicates that even if the surveillance data are not considered credible for determination of RT_{NDT}, “they may be credible for determining decrease in upper-shelf energy if the upper-shelf can be clearly determined, following the definition given in ASTM E 185-82”. Figure 2.1.2-1 provides the surveillance data points from Reference 3. RG 1.99, Rev. 2, Position 2.2 indicates that an upper-bound line drawn parallel to the existing lines (in Figure 2 of the Guide) through the surveillance data points should be used in preference to the existing graph lines for determining the decrease in USE.

c. Percentage USE Decrease is conservatively based on lowest Cu wt% chemistry line delineated in Figure 2 of NRC RG 1.99, Rev. 2.

Figure 2.1.2-1 RG 1.99, Revision 2, Predicted Decrease in Upper Shelf Energy as a Function of Copper and Fluence for Millstone Unit 3, Including Surveillance Data



2.1.3 Pressurized Thermal Shock

2.1.3.1 Regulatory Evaluation

The PTS evaluation provides a means for assessing the susceptibility of the RV belt line materials to PTS events to ensure that adequate fracture toughness is provided for supporting reactor operations. DNC reviewed the plant current license basis for the PTS methodology and the calculations for the referenced temperature (RT_{PTS}) at the expiration of license, considering neutron embrittlement effects.

The acceptance criteria are based on

- GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture.
- GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to ensure that, under specific conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized.
- 10 CFR 50.61, insofar as it sets fracture toughness criteria for protection against PTS events.

Specific review criteria are contained in the SRP Section 5.3.2 and the guidance provided in Matrix 1 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800), July 1981, Section 5.3.2, Rev. 1.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to:

- GDC-14, Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.14.

  The RCS boundary is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits (see FSAR Section 3.9). RCS pressure boundary materials, selection, and fabrication techniques ensure a low probability of gross rupture or abnormal leakage.

  In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions, such a seismic and pipe rupture, as discussed in FSAR Sections 3.6 and 3.7. The system is protected from overpressure by means of pressure relieving devices as required by applicable codes (see FSAR Section 5.2.2).

- GDC-31, Fracture Prevention of Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.31.

  Close control is maintained over material selection and fabrication for the RCS to ensure that the boundary behaves in a non-brittle manner. The RCS materials exposed to the coolant are corrosion-resistant stainless steel or Inconel. The nil ductility reference temperature of the RV structural steel is established by Charpy V-notch and drop weight tests, in accordance with 10 CFR 50, Appendix G. As part of the RV specification, certain requirements which are not specified by the applicable ASME Codes are performed as follows:

- A 100 percent volumetric ultrasonic test of reactor vessel plate for shear wave and a post-hydro test map of all full penetration ferritic pressure boundary welds in the pressure vessel are performed.

- Reactor vessel core region material chemistry (copper, phosphorus, and vanadium) is controlled to reduce sensitivity to embrittlement due to irradiation over the life of the plant.

- 10 CFR 50.61, Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events, is described in FSAR Section 5.2.3.3, as follows:

  In accordance with 10 CFR 50.61, RPV materials have been reviewed to establish a reference temperature for PTS (RT_{PTS}). This review evaluated core loading patterns and the actual amount of copper and nickel in the vessel materials. It also compared the vessel material composition and properties to surveillance capsule materials from which tests and measurements were taken.

  The maximum fluence level of 1.97 x 10^{19} n/cm^2, as determined by Westinghouse, was conservatively applied to all vessel locations to determine the end-of-life RT_{PTS}. This value is based on the results of the second surveillance capsule analysis as documented in WCAP-15405, Rev. 0,Analysis of Capsule X from the Northeast Nuclear Energy Company Millstone Unit 3 Reactor Vessel Radiation Surveillance Program, May, 2000 (Reference 1). FSAR Table 5.2-7 provides the results of the RT_{PTS} calculations. The values that were calculated do not exceed the RT_{PTS} screening criteria of 270^o F for plates, forgings, and axial weld materials, and 300^o F for circumferential weld materials. End-of-life RT_{PTS} projections are discussed in FSAR Section 5.3.2.2. Specifically, FSAR Table 5.3-4 provides the results of the calculation for limiting base and weld material.

The MPS3 RV was evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838 Section 4.2.3 is applicable for the TLAA for PTS.

2.1.3.2 Technical Evaluation

2.1.3.2.1 Introduction

Reactor vessel integrity is impacted by any change in plant parameters that affect neutron fluence levels or temperature/pressure transients. The changes in neutron fluence resulting from the SPU have been evaluated to determine the impact on reactor vessel integrity. The assessment presented herein focuses on the MPS3 reference temperatures for pressurized thermal shock at 54 EFPY.

2.1.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Definition of Reactor Vessel Beltline Materials

The beltline region of the reactor vessel is defined in 10 CFR 50, Appendix G, as the material (including welds, heat-affected zone, and plates or forgings) that directly surrounds the effective height of the active core and adjacent regions of the reactor vessel that are predicted to experience sufficient neutron radiation damage to be considered in the selection of the most limiting material with regard to radiation damage. By convention, the beltline materials evaluated have been limited to those that envelope the axial height of the active core. Traditionally-defined beltline materials have been extended to include all reactor vessel plates and welds that exceed $1x10^{17}$ n/cm^2 (E > 1.0 MeV) at the end of licensed plant operation. These additional plates and welds are appropriately called the “extended beltline” materials.

SPU Fluence Projections

Neutron fluence projections considering stretch power uprate conditions are presented in Tables 2.1.3-1 and 2.1.3-2 for the conventional beltline materials and extended beltline materials, respectively. The calculated fluence projections used in the SPU evaluation complied with RG 1.190. As these calculations were performed on a plant-by-plant basis, there was no generic topical report for the approved method. The methodology used was that of RG 1.190.

Inlet Temperature

As presented in Section 1.1, Nuclear Steam Supply System Parameters, the SPU full power reactor vessel inlet temperature range is 537.4°F to 556.4°F.

Chemistry Factor Values

The CFs, along with the FFs, are used to determine the shift in reference temperature, RT_{NDT}. The chemistry factor is a function of the copper and nickel content, and is determined in accordance with 10 CFR 50.61, Tables 1 and 2. In accordance with 10 CFR 50.61 Section (c)(2), those plate and weld materials that are part of a plant-specific surveillance program, must have material-specific chemistry factors calculated and incorporated into the determination of the RT_{NDT} if the surveillance data are deemed credible. The CFs used in this evaluation are presented in Table 2.1.3-3, along with the best-estimate copper and nickel chemistry used to calculate the CF values from 10 CFR 50.61, Tables 1 and 2. For clarity and consistency with RG 1.99, Rev. 2, CFs calculated based on chemistry are referred to as Position 1.1 and CFs calculated based on surveillance data are referred to as Position 2.1.

Initial Reference Temperature, Nil-Ductility Temperature (RT_{NDT})

The unirradiated material reference temperatures (RT_{NDT}) for the beltline materials were determined from laboratory testing as part of the development of the MPS3 Radiation Surveillance Program (see WCAP-10732, Reference 2). Unirradiated material reference temperatures were calculated for the extended beltline materials at MPS3 in CN-RCDA-04-34, Reference 3. These values are identified in Table 2.1.3-4 under the column $RT_{NDT(U)}$.

Acceptance Criteria

Criteria for acceptance of reference temperature predictions for pressurized thermal shock are provided in 10 CFR 50.61. The RT_{PTS} values must not exceed 270°F for plates, forgings, and axial welds, and below 300°F for circumferential welds.

The acceptance criteria for the reactor vessel inlet temperature are provided in U.S. NRC RG 1.99, Rev. 2, Radiation Embrittlement of Reactor Vessel Materials, which states that "The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement." Thus the reactor vessel inlet temperature must be greater than 525°F and less than 590°F for the equations and methodology of RG 1.99, Rev. 2, to remain valid.

2.1.3.2.3 Description of Analyses and Evaluations

The limiting condition on reactor vessel integrity known as pressurized thermal shock can occur during a severe system transient such as a LOCA or a steam line break. Such transients can challenge the integrity of a reactor vessel under the following conditions:

- Severe overcooling of the inside surface of the vessel wall followed by high repressurization
- Significant degradation of vessel material toughness caused by radiation embrittlement
- Presence of a critical-size defect in the vessel wall

The PTS concern arises if one of these transients should act on the beltline region of a reactor vessel where a reduced fracture resistance exists because of neutron irradiation. Such an event could cause the propagation of flaws postulated to exist near the inner wall surface, thereby potentially affecting the integrity of the vessel.

In 1985, the NRC issued a formal ruling on PTS. It established screening criteria on pressurized water reactor vessel embrittlement as measured by the RT_{PTS}. RT_{PTS} screening criteria values were set (using conservative fracture mechanics analysis techniques) for beltline axial welds, plates, and beltline circumferential weld seams for end-of-life plant operation. All PWR vessels in the U.S. have been required to evaluate vessel embrittlement in accordance with the criteria through end of life.

The NRC subsequently amended its regulations for LWRs changing the procedure for calculating radiation embrittlement. The revised PTS rule was published in the Federal Register, December 19, 1995, with an effective date of January 18, 1996. This amendment made the procedure for calculating RT_{PTS} values consistent with the methods given in RG 1.99, Rev. 2.

The PTS rule establishes the following requirements for all domestic, operating PWRs:

- For each PWR that has had an operating license issued, the licensee will have projected values of RT_{PTS} accepted by the NRC, for each reactor vessel beltline material for the EOL fluence of the material.
- The assessment of RT_{PTS} must use the calculation procedures given in the PTS Rule and must specify the bases for the projected value of RT_{PTS} for each beltline material. The report

must specify the copper and nickel contents and the fluence values used in the calculation for each beltline material.

- This assessment must be updated whenever there is significant change in projected values of RT_{PTS}, or upon the request for a change in the expiration date for operation of the facility. Changes to RT_{PTS} values are significant if either the previous value or the current value, or both values, exceed the screening criterion prior to the expiration of the operating license, including any license renewal term, if applicable for the plant.
- The RT_{PTS} screening criteria values for the beltline region are:
  - 270 F for plates, forgings, and axial weld materials
  - 300 F for circumferential weld materials
- RT_{PTS} must be calculated for each vessel beltline material using a fluence value, f, which is the EOL fluence for the material.

Per 10 CFR 50.61 the following equations and variables are to be used for calculating EOL RT_{PTS} values at the clad/base metal interface of the vessel.

$$RT_{PTS} = RT_{NDT(U)} + M + \Delta RT_{PTS}$$

where,

$RT_{NDT(U)}$ = Initial RT_{NDT} value, °F

M = $\text{Margin} = 2\sqrt{\sigma_i^2 + \sigma_\Delta^2}$ (°F)

σ_i = 0°F when Initial RT_{NDT} is a measured value

σ_i = 17°F when Initial RT_{NDT} is a generic value

For plates and forgings:

σ_Δ = 17°F when surveillance capsule data is not used

σ_Δ = 8.5°F when credible surveillance capsule data is used

For welds:

σ_Δ = 28°F when surveillance capsule data is not used

σ_Δ = 14°F when credible surveillance capsule data is used

(σ_Δ not to exceed 0.5*ΔRT_{PTS})

$\Delta RT_{PTS} = CF * f^{(0.28 - 0.10 \log f)}$

where,

CF = chemistry factor (°F)

f = neutron fluence (10^{19} n/cm^2, E>1.0 MeV) at the clad/base metal interface on the inside surface of the vessel

In accordance with 10 CFR 50.61, RT_{PTS} values under SPU conditions were calculated for the vessel beltline and extended beltline materials for a design life of 54 EFPY.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Section 4.2.1.3 of NUREG-1838 states: “Millstone Unit 3 uses a fluence methodology in accordance with DG-1053, and the specific methodology applied to the calculation followed the guidance of RG 1.190. DG-1053 is the draft version of RG 1.190 and provides similar conservatism when calculating the reactor vessel fluence values. Therefore, for MPS3, the fluence values meet the guidelines of RG 1.190 and are acceptable to the staff.”

DNC has evaluated the impact of the SPU on the conclusions for PTS of the MPS3 beltline materials reached in the license renewal application. Updated neutron fluence projections accounting for the stretch power uprate are lower in magnitude than the projections of fluence used in the license renewal application for calculating PTS values of the beltline materials at 54 EFPY. The license renewal application used a surface fluence of $3.31x10^{19}$ n/cm^2 (see Table 4.2-2 of the Millstone Unit 3 License Renewal Application) in its PTS calculations for MPS3 beltline materials at 54 EFPY, and demonstrated satisfactory margin below the respective PTS screening criteria of 270°F for plates, forgings, and axial welds, and 300°F for circumferential welds. The updated surface fluence of $2.70x10^{19}$ n/cm^2 was used in the current calculations of MPS3 beltline and extended beltline material PTS values at 54 EFPY, as provided in Table 2.1.3-4, and does not impact the PTS results previously determined using the higher neutron fluence.

2.1.3.2.4 Results

Calculated RT_{PTS} Values, and the interim calculations to obtain these values, are contained in Table 2.1.3-4. The limiting material is Intermediate Shell Plate B9805-1, with the more limiting RT_{PTS} value occurring for calculations using the RG 1.99, Rev. 2, Position 1.1 Chemistry Factor, as opposed to the Position 2.1 Chemistry Factor calculated from credible surveillance data. The most limiting RT_{PTS} value at 54 EFPY for Plate B9805-1 is 133°F. This value is substantially below the NRC screening criteria for vessel plates of 270°F.

All of the beltline and extended beltline materials in the MPS3 reactor vessel are below the RT_{PTS} screening criteria values of 270°F for axially oriented welds, plates, and forgings, and 300°F for circumferentially oriented welds, at 54 EFPY. DNC has evaluated the impact of the SPU on the projected values of RT_{PTS} for beltline and extended beltline materials in the MPS3 vessel. The most limiting beltline material, with respect to PTS, is Intermediate Shell Plate B9805-1. The RT_{PTS} value for this material at 54 EFPY is below the 10 CFR 50.61 screening criteria for plates, forgings, and axial welds. DNC finds the proposed SPU acceptable with respect to PTS. DNC further concludes that the vessel integrity evaluation is appropriate to ensures that MPS3 continues to meet the requirements of 10 CFR 50.61 and provides information to ensure continued compliance with GDC-14 and GDC-31 in this respect following implementation of the proposed SPU.

Furthermore, since the MPS3 reactor vessel inlet temperature is being maintained between 525°F and 590°F, the equations and results for predicting RT_{NDT} and pressurized thermal shock reference temperature (RT_{PTS}) remain valid without any adjustments for temperature effects.

2.1.3.3 Conclusion

DNC has reviewed the evaluation of the effects of the proposed SPU for MPS3 and concludes that the evaluation has adequately addressed changes in neutron fluence and their effects on PTS. DNC further concludes that the evaluation has demonstrated that the plant will continue to meet the requirements of GDC-14, GDC-31, and 10 CFR 50.61 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to PTS.

2.1.3.4 References

1. WCAP-15405, Rev. 0, Analysis of Capsule X from the Northeast Nuclear Energy Company Millstone Unit 3 Reactor Vessel Radiation Surveillance Program, E. Terek, et al, May 2000.

2. WCAP-10732, Northeast Utilities Service Company Millstone Unit No. 3 Reactor Vessel Radiation Surveillance Program, L. R. Singer, June 1985.

3. Westinghouse Calculation: CN-REA-04-34, Millstone Unit 3 Reactor Vessel Integrity Evaluations for an Extended Beltline, June 2004.

Table 2.1.3-1 Calculated Maximum Neutron Exposure of the Reactor Vessel Beltline Materials at the Clad/Base Metal Interface

Operating Time [EFPY]	Azimuthal Location			
	0.0 Degrees	15.0 Degrees	30.0 Degrees	45.0 Degrees
	Neutron Fluence [n/cm^2, (E > 1.0 MeV)]			
13.8 (EOC 10)	4.53E+18	6.68E+18	7.55E+18	7.49E+18
15.1	4.91E+18	7.20E+18	8.20E+18	8.18E+18
16.6	5.26E+18	7.76E+18	8.88E+18	8.88E+18
18.1	5.68E+18	8.35E+18	9.59E+18	9.54E+18
19.5	6.11E+18	8.99E+18	1.04E+19	1.03E+19
25.0	7.71E+18	1.12E+19	1.29E+19	1.27E+19
32.0	9.77E+18	1.41E+19	1.63E+19	1.57E+19
36.0	1.10E+19	1.58E+19	1.82E+19	1.75E+19
40.0	1.22E+19	1.75E+19	2.02E+19	1.93E+19
48.0	1.46E+19	2.09E+19	2.40E+19	2.28E+19
54.0	1.64E+19	2.34E+19	2.70E+19	2.55E+19
60.0	1.82E+19	2.59E+19	2.99E+19	2.81E+19

Table 2.1.3-2 Calculated Neutron Exposure of the Reactor Vessel Beltline and Extended Beltline Materials at the Clad/Base Metal Interface

Azimuth [Deg.]	MPS3 Beltline and Extended Beltline Materials	Neutron Fluence [n/cm^2, E > 1.0 MeV]	
		54 EFPY	**60 EFPY**
0	Outlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Inlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Nozzle Shell Plates (B9804-1, B9804-2, B9804-3)	5.18E+17	5.78E+17
	Nozzle Shell 0 Degree Long. Weld (101-122)	5.18E+17	5.78E+17
	Int. Shell to Nozzle Shell Circ. Weld (103-121)	5.18E+17	5.78E+17
	Int. Shell Plates (B9805-1, B9805-2, B9805-3)	1.62E+19	1.82E+19
	Int. Shell 0 Degree Long. Weld (101-124)	1.62E+19	1.82E+19
	Lower Shell to Int. Shell Circ. Weld (101-171)	1.62E+19	1.82E+19
	Lower Shell Plates (B9820-1, B9820-2, B9820-3)	1.64E+19	1.82E+19
	Lower Shell 0 Degree Long. Weld (101-142)	1.64E+19	1.82E+19
	Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17	<1.0E+17
15	Outlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Inlet Nozzles and Nozzle Welds	1.10E+17	1.22E+17
	Nozzle Shell Plates (B9804-1, B9804-2, B9804-3)	7.37E+17	8.22E+17
	Int. Shell to Nozzle Shell Circ. Weld (103-121)	7.37E+17	8.22E+17
	Int. Shell Plates (B9805-1, B9805-2, B9805-3)	2.31E+19	2.56E+19
	Lower Shell to Int. Shell Circ. Weld (101-171)	2.31E+19	2.56E+19
	Lower Shell Plates (B9820-1, B9820-2, B9820-3)	2.34E+19	2.59E+19
	Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17	<1.0E+17
30	Outlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Inlet Nozzles and Nozzle Welds	1.27E+17	1.41E+17
	Nozzle Shell Plates (B9804-1, B9804-2, B9804-3)	8.51E+17	9.49E+17
	Nozzle Shell 30 Degree Long. Welds (101-122)	8.51E+17	9.49E+17
	Int. Shell to Nozzle Shell Circ. Weld (103-121)	8.51E+17	9.49E+17
	Int. Shell Plates (B9805-1, B9805-2, B9805-3)	2.66E+19	2.95E+19
	Int. Shell 30 Degree Long. Welds (101-124)	2.66E+19	2.95E+19
	Lower Shell to Int. Shell Circ. Weld (101-171)	2.66E+19	2.95E+19
	Lower Shell Plates (B9820-1, B9820-2, B9820-3)	2.70E+19	2.99E+19
	Lower Shell 30 Degree Long. Welds (101-142)	2.70E+19	2.99E+19
	Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17	<1.0E+17

Table 2.1.3-2 Calculated Neutron Exposure of the Reactor Vessel Beltline and Extended Beltline Materials at the Clad/Base Metal Interface

Azimuth [Deg.]	MPS3 Beltline and Extended Beltline Materials	Neutron Fluence [n/cm^2, E > 1.0 MeV]	
		54 EFPY	60 EFPY
45	Outlet Nozzles and Nozzle Welds	<1.0E+17	<1.0E+17
	Inlet Nozzles and Nozzle Welds	1.20E+17	1.33E+17
	Nozzle Shell Plates (B9804-1, B9804-2, B9804-3)	8.03E+17	8.93E+17
	Int. Shell to Nozzle Shell Circ. Weld (103-121)	8.03E+17	8.93E+17
	Int. Shell Plates (B9805-1, B9805-2, B9805-3)	2.52E+19	2.78E+19
	Lower Shell to Int. Shell Circ. Weld (101-171)	2.52E+19	2.78E+19
	Lower Shell Plates (B9820-1, B9820-2, B9820-3)	2.55E+19	2.81E+19
	Lower Head to Lower Shell Circ. Weld (101-141)	<1.0E+17	<1.0E+17

Table 2.1.3-3 Summary of the MPS3 Beltline and Extended Beltline Material Properties and Chemistry Factors Based on RG 1.99, Rev. 2

Material	Wt. % Cu	Wt. % Ni	Position 1.1 CF	Position 2.1 CF
Intermediate Shell Plate B9805-1	0.05	0.63	31.0°F	26.7°F
Intermediate Shell Plate B9805-2	0.05	0.64	31.0°F	- - -
Intermediate Shell Plate B9805-3	0.05	0.65	31.0°F	- - -
Lower Shell Plate B9820-1	0.08	0.63	51.0°F	- - -
Lower Shell Plate B9820-2	0.07	0.60	44.0°F	- - -
Lower Shell Plate B9820-3	0.06	0.61	37.0°F	- - -
Beltline Region Weld Metal[(a)]	0.05	0.05	31.8°F	6.7°F
Nozzle Shell Plate B9804-1	0.05	0.62	31°F	- - -
Nozzle Shell Plate B9804-2	0.08	0.64	51°F	- - -
Nozzle Shell Plate B9804-3	0.05	0.65	31°F	- - -
Inlet Nozzle B9806-3	0.09	0.83	58°F	- - -
Inlet Nozzle B9806-4	0.09	0.82	58°F	- - -
Inlet Nozzle R5-3	0.07	0.80	44°F	- - -
Inlet Nozzle R5-4	0.08	0.81	51°F	- - -
Nozzle Shell Longitudinal Weld 101-122A	0.05	0.12	39.8°F	- - -
Nozzle Shell Longitudinal Weld 101-122B, 101-122C	0.05	0.12	39.8°F	- - -
Nozzle Shell to Intermediate Shell Girth Weld 103-121	0.05	0.13	41°F	- - -
Inlet Nozzle Weld 105-121A	0.09	0.05	45.3°F	- - -
Inlet Nozzle Weld 105-121B	0.16	0.06	75.4°F	- - -
Inlet Nozzle Weld 105-121C	0.16	0.06	75.4°F	- - -
Inlet Nozzle Weld 105-121D	0.16	0.06	75.4°F	- - -

Notes:

a. MPS3 beltline welds were all fabricated using the same weld heat - #4P6052, flux type - Linde 0091, and flux lot number - 0145. The beltline welds include the intermediate to lower shell girth weld seam and the longitudinal weld seams in the intermediate shell course and lower shell course.

Table 2.1.3-4 RT_{PTS} Calculations for MPS3 Beltline and Extended Beltline Materials at 54 EFPY

Material	RG 1.99 R2 Method	CF (°F)	Fluence (10^{19} n/cm^2)	FF[(a)]	ΔRT_{PTS}[(b)] (°F)	$RT_{NDT(U)}$[(c)] (°F)	Margin[(d)] (°F)	RT_{PTS}[(e)] (°F)
Intermediate Shell Plate B9805-1	Position 1.1	31.0	2.70	1.265	39.22	60	34.0	133
	Position 2.1	26.7	2.70	1.265	33.77	60	17.0	111
Intermediate Shell Plate B9805-2	Position 1.1	31.0	2.70	1.265	39.22	10	34.0	83
Intermediate Shell Plate B9805-3	Position 1.1	31.0	2.70	1.265	39.22	0	34.0	73
Lower Shell Plate B9820-1	Position 1.1	51.0	2.70	1.265	64.53	10	34.0	109
Lower Shell Plate B9820-2	Position 1.1	44.0	2.70	1.265	55.67	40	34.0	130
Lower Shell Plate B9820-3	Position 1.1	37.0	2.70	1.265	46.81	20	34.0	101
Intermediate Shell Longitudinal Weld Seams 101-124 A,B,C[(f)]	Position 1.1	31.8	2.70	1.265	40.23	-50	40.23	30
	Position 2.1	6.7	2.70	1.265	8.43	-50	8.43	-33
Intermediate to Lower Shell Girth Weld Seam 101-171[(g)]	Position 1.1	31.8	2.70	1.265	40.23	-50	40.23	30
	Position 2.1	6.7	2.70	1.265	8.43	-50	8.43	-33
Lower Shell Longitudinal Weld Seams 101-142 A,B,C[(f)]	Position 1.1	31.8	2.70	1.265	40.23	-50	40.23	30
	Position 2.1	6.7	2.70	1.265	8.43	-50	8.43	-33
Nozzle Shell Plate B9804-1	Position 1.1	31	0.0851	0.3854	11.95	40	11.95	64

Table 2.1.3-4 RT_{PTS} Calculations for MPS3 Beltline and Extended Beltline Materials at 54 EFPY

Material	RG 1.99 R2 Method	CF (°F)	Fluence (10^{19} n/cm^2)	FF[(a)]	ΔRT_{PTS} [(b)] (°F)	$RT_{NDT(U)}$ [(c)] (°F)	Margin[(d)] (°F)	RT_{PTS} [(e)] (°F)
Nozzle Shell Plate B9804-2	Position 1.1	51	0.0851	0.3854	19.65	20	19.65	59
Nozzle Shell Plate B9804-3	Position 1.1	31	0.0851	0.3854	11.95	0	11.95	24
Inlet Nozzle B9806-3	Position 1.1	58	0.0851	0.3854	22.35	10	22.35	55
Inlet Nozzle B9806-4	Position 1.1	58	0.0851	0.3854	22.35	0	22.35	45
Inlet Nozzle R5-3	Position 1.1	44	0.0851	0.3854	16.96	-10	16.96	24
Inlet Nozzle R5-4	Position 1.1	51	0.0851	0.3854	19.65	0	19.65	39
Nozzle Shell Longitudinal Weld 101-122A [(f)]	Position 1.1	39.8	0.0851	0.3854	15.34	-10	15.34	21
Nozzle Shell Longitudinal Welds 101-122B, 101-122C [(f)]	Position 1.1	39.8	0.0851	0.3854	15.34	-50	15.34	-19
Nozzle Shell to Intermediate Shell Girth Weld 103-121 [(g)]	Position 1.1	41	0.0851	0.3854	15.80	-40	15.80	-8
Inlet Nozzle Weld 105-121A [(f)]	Position 1.1	45.3	0.0851	0.3854	17.46	-60	17.46	-25
Inlet Nozzle Weld 105-121B [(f)]	Position 1.1	75.4	0.0851	0.3854	29.06	-50	29.06	8

Table 2.1.3-4 RT_{PTS} Calculations for MPS3 Beltline and Extended Beltline Materials at 54 EFPY

Material	RG 1.99 R2 Method	CF (°F)	Fluence (10^{19} n/cm²)	FF[(a)]	ΔRT_{PTS} [(b)] (°F)	$RT_{NDT(U)}$ [(c)] (°F)	Margin[(d)] (°F)	RT_{PTS} [(e)] (°F)
Inlet Nozzle Weld 105-121C [(f)]	Position 1.1	75.4	0.0851	0.3854	29.06	-50	29.06	8
Inlet Nozzle Weld 105-121D [(f)]	Position 1.1	75.4	0.0851	0.3854	29.06	-50	29.06	8

Notes:

a. FF = fluence factor = $f^{(0.28 - 0.1 \log (f))}$

b. ΔRT_{PTS} = CF * FF

c. Initial RT_{NDT} values are measured values

d. $M = 2 * (\sigma_i^2 + \sigma_\Delta^2)^{1/2}$

e. $RT_{PTS} = RT_{NDT(U)} + \Delta RT_{PTS}$ + Margin (°F)

f. These welds are considered to have an axial orientation with respect to the PTS Screening Criteria.

g. These welds are considered to have a circumferential orientation with respect to the PTS Screening Criteria.

2.1.4 Reactor Internal and Core Support Materials

2.1.4.1 Regulatory Evaluation

The reactor internals and core supports include SSCs that perform safety functions or whose failure could affect safety functions performed by other SSCs. These safety functions include:

- Reactivity monitoring and control
- Core Cooling
- Fission product confinement (within both the fuel cladding and the RCS)

The DNC review covered:

- The materials' specifications and mechanical properties
- Welds
- Weld controls
- NDE procedures
- Corrosion resistance
- Susceptibility to degradation

The acceptance criteria are based on:

- GDC-1 and 10 CFR 50 Part 55a for material specifications, controls on welding, and inspection of reactor internals and core supports.

Specific review criteria are contained in the SRP, Section 4.5.2, BAW-2248 (Applies only to B&W plants-N/A to MPS3) and the guidance provided in Matrix 1 of RS-001.

DNC reviewed the reactor internal and core support materials considering the guidance in WCAP-14577, Rev. 1, "License Renewal Evaluation: Aging Management for Reactor Internalize.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800) and SRP Section 4.5.2 (Rev. 2).

As noted in the FSAR, Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to:

- GDC-1 is described in the FSAR Section 3.1.2.1, General Design Criterion 1 - Quality Standards and Records.

  SSCs important to safety are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

Quality standards applicable to safety related SSCs are generally contained in codes such as the ASME B&PV Code. The applicability of these codes is specifically identified throughout this report and is summarized in FSAR Section 3.2.5. FSAR Section 17.1 provides direct reference to the Quality Assurance Program established to provide assurance that safety related SSCs satisfactorily perform their intended safety functions. The procedures for generating and maintaining appropriate design, fabrication, erection, and testing records are contained within the referenced documents.

The specifications for materials used for RVI components are shown in FSAR Table 5.2-3. FSAR Section 4.5.2 provides information on RVI materials, controls on welding, and the cleaning and fabrication of stainless steel RVI components. FSAR Section 5.2.3.4.4 summarizes the 4 point program designed to prevent intergranular attack of austenitic stainless steel components.

- 10 CFR 50.55(a) is described in FSAR Section 5.2.1.1, Compliance with 10 CFR 50.55(a). RCS components are designed and fabricated in accordance with 10 CFR 50.55a. The actual addenda of the ASME Code applied in the original design of each component are listed in FSAR Table 5.2-1.

Details of the RVI and their design conditions are provided in FSAR Sections 3.9N.1, 3.9N.5, 4.2 and 4.5.

FSAR Section 3.9N.5.1 states:

- The components of the reactor internals are divided into three parts, consisting of the lower core support assembly, (including the entire core barrel and neutron shield pad assembly), the upper core support assembly and the incore instrumentation support tube. The reactor internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and CRDM's, direct coolant flow past the fuel elements, direct coolant flow to the pressure vessel head, provide gamma and neutron shielding, and provide guides for the incore instrumentation.
- The major containment and support member of the reactor internals is the lower core support assembly, shown in Figure 3.9N-8. This assembly consists of the core barrel, the core baffle, the lower core plate and support columns, the neutron shield pads, and the core support, which is welded to the core barrel. The major material for this assembly is Type 304 stainless steel. The lower core support assembly is supported at its upper flange from a ledge in the reactor vessel flange and its lower end is restrained in its transverse movement by a radial support system attached to the vessel wall.

  The neutron shield panel design for MPS3 consists of four sets of stainless steel plates strategically placed on the core barrel in areas of peak fast neutron flux on the reactor pressure vessel. See Figures 3.9N-11 and 3.9N-12. Attachment of each of the plate sections to the core barrel is accomplished through a series of sixteen 7/8-inch stainless steel bolts and three 2-3/8-inch stainless steel pins.
- The upper core support assembly, shown in Figure 3.9N-9 and 3.9N-10 consists of the upper support, the upper core support plate, the support columns, and the guide tube assemblies. The support columns establish the spacing between the upper support and the upper core

plate. They are fastened at the top and bottom to these plates. The support columns transmit the mechanical loading between the two plates and serve the supplementary function of supporting thermocouples.

The MPS3 reactor internals components and core support materials were evaluated for continued acceptability for continued operation and to support plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3”, dated August 1, 2005, documents the results of that review. NUREG-1838, Sections 2.3B.1.2 and 3.1B.2.3.2 are applicable to the reactor internals and core support structural components.

NUREG 1838, Appendix A, Commitments for License Renewal of MPS Unit 3, Items 13, 14 and 15 percent commitments concerning license renewal regarding RVI components.

2.1.4.2 Technical Evaluation

2.1.4.2.1 Introduction

This section of the report summarizes the evaluations, and their results, of the potential materials degradation issues arising from the effect of SPU on the performance of reactor internals and core support materials at MPS3.

The WOG Life Cycle Management & License Renewal Program prepared topical report WCAP–14577, License Renewal Evaluation: Aging Management for Reactor Internals. The topical report describes the aging degradation mechanisms to determine the aging effects. All identified effects are evaluated to determine that the aging effects are being managed to ensure RVI components perform their intended functions. The evaluation also included the time-limited aging analyses (TLAAs). The report has been utilized in the NRC aging management review of the MPS3 RVI components.

The NRC review of the WOG topical report concluded that the report provides an acceptable demonstration that the applicable effects of aging on reactor vessel internals components will be adequately managed for the WOG plants, such that there is a reasonable assurance that the RVI components will perform their intended functions in accordance with the current licensing basis during the remainder of the base licensing period, as well as, the period of extended operation. The SPU evaluation considered potential changes in the aging effects due to the change in the service conditions resulting from the proposed SPU conditions. These are considered below:

The primary objective of the SPU assessment was to ensure that the new SPU environmental conditions (chemistry, temperature, and fluence) do not introduce any new aging effects on the RVI components during the remainder of the base licensing period or the extended licensing years 40-60, nor change the manner in which the component aging is managed by the aging management program credited in the topical report WCAP-14577, Rev. 1-A, “License Renewal Evaluation: Aging Management for Reactor Vessel Internals”, and accepted by the NRC in the SER.

The relevant potentially impacted degradation (aging) mechanisms are:

- Integrity of reactor vessel fuel cladding materials,

- TGSCC, and IGSCC of stainless steels,
- PWSCC of Alloy 600 and Alloy X-750 components,
- Neutron Irradiation Embrittlement and Void Swelling of austenitic steel material internals, and
- IASCC of stainless steels.

An assessment of these aging mechanisms is considered in the following subsections.

2.1.4.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Proposed SPU Service Conditions

The SPU will cause the following changes in the RCS chemistry conditions, neutron fluence levels, and temperatures (Reference 5):

- The reactor coolant lithium/boron chemistry program is coordinated such that a target pH range between 7.11 and 7.20 is maintained with an initial maximum target lithium level of 3.5 ppm. The lithium level is then decreased gradually during the fuel cycle as the boron diminishes, thus maintaining a target pH value of 7.20 through the end of the fuel cycle (Westinghouse chemistry guidelines recommends the at temperature pH to be maintained between 6.90 and 7.40).
- The estimated maximum fast neutron (E>0.1 MeV) exposure of the MPS3 reactor internals for operating periods of 32 and 54 EFPY are summarized in Table 2.1.4-1. The values shown for 13.8 EFPY and the SPU have been extrapolated from calculations of the reactor pressure vessel fluence and were based, in part, on work that was completed to support pressure vessel integrity evaluations for the SPU program. These maximum exposures occur on the inside surface of the baffle plates opposite the central sections of the reactor core. The estimated exposures as a result of the SPU are compared to the Design Basis values as well as the estimated exposures at the end of Cycle 10 (13.8 EFPY). Note that the estimated exposures as a result of the SPU are less than the Design Basis values for both 32 and 54 EFPY. This occurs due to the use of low leakage cores. While the estimated exposures as a result of the SPU are more than the current estimates at 32 EFPY, at 54 EFPY the estimates are nearly equal.
- A maximum increase ΔT in the peak steady state service temperature of 4.3°F at the reactor vessel hot leg location and an increase ΔT in service temperature of 0.5°F at the reactor vessel cold leg and BMI penetration locations will occur due to the SPU. This is summarized in Table 2.1.5-1.

2.1.4.2.3 Description of Analyses and Evaluations

The effect of changes in service conditions due to the proposed SPU on the performance of the reactor vessel internals materials is discussed in the following paragraphs.

Materials Specifications, Weld Controls and NDT Inspections

The NRC's acceptance criteria for reactor internals and core support materials are based on GDC-1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of reactor internals and core supports. The review of MPS3 covered the materials' specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation. Specific review criteria are contained in SRP Section 4.5.2 and WCAP-14577. The proposed SPU is not expected to cause negative affects.

Stress Corrosion Cracking

The two degradation mechanisms that are operative in the internals austenitic stainless steels are IGSCC and TGSCC. The occurrence of IGSCC in austenitic stainless steel typically requires the presence of a sensitized microstructure and a significant level of dissolved oxygen. The prerequisites for TGSCC in austenitic stainless steels include a significant level of dissolved oxygen and some level of halogens (such as chlorides). If dissolved oxygen levels are high, TGSCC can occur in annealed stainless steels at chloride levels below the maximum level permitted during operation by the EPRI PWR primary water chemistry guidelines. The principal method of preventing IGSCC and TGSCC is by water chemistry control. The reactor coolant chemistry must be rigorously controlled, particularly with regard to oxygen, chlorides and other halogens. Ingress from other species, such as demineralizer resins, is carefully monitored, and corrective actions are taken to preclude exposure. The minimal increase in temperature due to the SPU would not affect IGSCC or TGSCC of austenitic stainless steels.

PWSCC is another form of IGSCC degradation that has been observed in Alloy 600 and Alloy X-750 materials in PWR applications. The RCCA guide tube support pins and clevis insert bolts at MPS3 are fabricated from X-750 material; the clevis inserts are manufactured from Alloy 600 material.

The cracking of X-750 material is attributed to a combination of high stress and undesirable microstructure. The heat treatment specification for the replacement split pin material and the support pin design at MPS3 was to provide a more PWSCC resistant microstructure and lower stress condition. The Alloy X-750 clevis insert bolts in older plant designs experienced cracking in some plants after approximately 13 years of operation. However the degradation of clevis insert bolts would not result in a loss of intended function since the design geometry is such that the insert sits in a constrained groove and degradation of the bolts would not cause the displacement of the clevis insert from its original position. MPS3 has future plans for replacing the X-750 guide tube support pins with cold worked stainless steel; until then the minimal increase in temperature due to the SPU would not increase degradation of the X-750 material.

The Alloy 600 clevis inserts experience lower fluence, temperature, and stresses in comparison to the support pins. The clevis inserts experience essentially compressive stress and no failures have been reported. Furthermore, like the clevis insert bolts; a failure of the clevis inserts would not result in a loss of intended function due to the nature of the design. Therefore, the effects of PWSCC on the clevis inserts are not significant. The slight temperature increase would not be detrimental to the Alloy 600 clevis inserts.

The topical report WCAP-14577, Rev. 1-A, "License Renewal Evaluation: Aging Management for Reactor Vessel Internals", considered the potential SCC degradation and concluded that the effects of all forms of SCC are not significant for Alloy 600, X-750, and stainless steel RVI components. The NRC review of the topical report concluded that there is a reasonable assurance that the RVI components will perform their intended functions in accordance with the current licensing basis during the period of extended operation.

The proposed SPU chemistry program at MSP3 suggested operating at an elevated 7.2pH level (up to 1500 ppm Boron), while the Lithium level is maintained at less than or close to 3.5 ppm. The chemistry changes resulting from the SPU do not involve introduction of any of the (stress, oxygen or halogen) contributors for stress corrosion cracking, therefore no impact on the stress corrosion cracking material degradation is expected in the RVI components as a result of the SPU.

Fuel-Cladding Corrosion Effects

The proposed MPS3 SPU lithium, boron, and pH management program was reviewed. The proposed chemistry program for SPU suggested operating at an elevated 7.2 pH level (up to 1500 ppm Boron), while the target lithium level is maintained at less than or close to 3.5 ppm. These conditions are bounded by the proposed EPRI chemistry guidelines (Reference 1). Since these guidelines are specifically designed to prevent fuel-cladding corrosion effects such as fuel deposit buildup and Alloy 600 PWSCC, there is no adverse effect on fuel-cladding corrosion. Experience with operating plants as well as with the guidelines provided by EPRI (Reference 1) suggests that increasing initial lithium concentrations up to 3.5 ppm with controlled boron concentrations to maintain pH values ranging from 6.9 to 7.4 has not produced any undesirable material integrity issues that could be statistically defined from the database of lab results available in 2003.

Irradiation Embrittlement

Irradiation embrittlement is possible in the reactor internals components fabricated from austenitic stainless steel and nickel-based alloys with expected neutron fluences in excess of 1×10^{21} n/cm^2 (E > 0.1 MeV). If the expected neutron fluence is less than approximately 1×10^{21} n/cm^2 (E > 0.1 MeV), then the changes in mechanical properties due to neutron exposure are insignificant. The reactor internals components with fluences greater than 1×10^{21} n/cm (E > 0.1 MeV) (e.g., lower core barrel, baffle/former assembly, baffle/former bolts, lower core plate and fuel pins, lower support forging, clevis bolts) are potentially susceptible to irradiation embrittlement.

The MPS3 SPU expected maximum fast neutron exposure levels of the reactor internals for operating periods of 32 and 54 EFPY are listed in Section 2.1.4.2.2 above. Experience has shown that the following RVI components are exposed to the highest in-core neutron radiation fields and hence are most susceptible to crack initiation and growth due to IASCC and loss of fracture toughness due to neutron irradiation embrittlement and/or void swelling:

- Lower core plate and fuel alignment pins
- Lower support columns
- Core barrel and core barrel flange in active core region
- Thermal shield
- Bolting-lower support column, baffle-former, and barrel-former

Data from power reactor irradiation of Type 304 and Type 316 stainless steel are available from several studies (Reference 2, 3, and 4). Embrittlement, as evidenced by increases in yield strength and decreases in uniform and total elongation, is common in these materials after irradiation. Studies (Reference 2, and 3) showed that embrittlement of stainless steel can occur at fluences as low as 1 x 10^{21} n/cm^2 (E > 0.1 MeV) in the more susceptible stainless steel materials such as 304SS. These same studies showed that the rate of change in mechanical properties is reduced at fluences above 2 x 10^{22} n/cm^2 (E > 0.1 MeV).

No instance of service related internals degradation has been recorded that can be directly attributed to irradiation embrittlement. However, the end-of-life fluence level for some internals components at MPS3 is approximately 1 x 10^{23} n/cm^2 (E > 0.1 MeV), therefore DNC has committed to follow the industry Materials Reliability Program/Issues Task Group efforts on reactor internals and monitor developments in this area. MPS3 license renewal SER (NUREG-1801) states in Section 3.1B2.2.6 that:

> "However, since the EPRI Materials Research Project - Reactor Internals Issue Task Group is currently addressing this issue, the applicant will follow the industry effort related to void swelling and will implement the appropriate recommendations resulting from this guidance. In addition, the applicant has identified the implementation of the industry initiatives as commitment 13 in Appendix A, Table A6.0-1 of the LRA. Further evaluation of this program and the commitment to updating this program is addressed in Section 3.0.3.2.12 (AMP B2.1.17) of this SER."

Commitment 13 states that:

> "Millstone will follow the industry efforts on reactor vessel internals regarding such issues as thermal or neutron irradiation embrittlement (loss of fracture toughness), void swelling (change in dimensions), stress corrosion cracking (PWSCC and IASCC), and loss of pre-load for baffle and former-assembly bolts and will implement the appropriate recommendations resulting from this guidance".

This commitment will be implemented as a part of the ISI Program: Reactor Vessel Internals and will be implemented prior to the Period of Extended Operation.

The NRC's review (MPS3 License Renewal SER) concluded that the DNC approach to aging management for MPS3 identified in the LRA is consistent with the GALL Report (NUREG-1801) and that DNC has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis for the period of extended operation as required by 10 CFR 54.21(a)(3).

There are a number of industry activities currently underway to characterize and address aging effects on reactor vessel internals under the EPRI Materials Reliability Project (MRP). As a result of these efforts, further understanding of these aging effects is being developed by the industry to provide additional bases for whether inspections over and beyond those currently required by ASME Section XI should be implemented. The MRP strategy is to evaluate potential aging mechanisms and their effects on specific reactor vessel internals parts by evaluating causal parameters such as fluence, material properties, state of stress, etc. Critical locations can thereby be identified and tailored inspections can be conducted on either an integrated industry, NSSS, or plant-specific basis. The MRP projects include material testing of baffle/former bolts removed from the Point Beach, Farley, and Ginna nuclear power plants and determination of bolt operating parameters.

Void Swelling

Void swelling is the gradual increase in size (physical dimension) of the RVI stainless steel component caused by the formation and growth of helium-vacancy clusters into voids due to the effect of irradiation. Although the effects of swelling can be potentially significant for those components which experience significant neutron irradiation while operating at elevated temperatures, the actual plant operations do not appear to produce the conditions necessary for significant swelling. At MPS3 while gamma heating is shown to slightly increase due to the SPU the increase is still less than the design basis and the maximum possible temperature increase still would not produce the necessary conditions for significant swelling. This would hold through life extension. Recent data from Point Beach and Farley suggested very small (0.01 percent to 0.03 percent) amounts of swelling in baffle bolts. Extrapolation of these data using a simple square law suggests no concern with respect to void swelling until the end of extended life in U.S. PWRs. Fuel management schemes to reduce neutron leakage from the core have reduced one of the major factors contributing to swelling, and mechanisms such as creep and stress relaxation serve to reduce some of the adverse effects. The topical report WCAP-14577, Rev. 1-A, “License Renewal Evaluation: Aging Management for Reactor Vessel Internals”, examined the effects of swelling and concluded that any actual swelling of the susceptible internals will not prevent them from performing their intended function during the license renewal period.

Industry data on swelling are currently being evaluated as part of the WOG and MRP. At present there have been no indications from the different bolt removal programs or functional ‘evaluations’ that there are any discernible effects attributable to swelling. DNC continues to participate and follow up industry efforts to investigate swelling effects on the reactor vessel internals.

Thermal Aging

Thermal aging of cast austenitic stainless steel can lead to precipitation of additional phases in the ferrite and growth of existing carbides at the ferrite/austenitic boundaries that can result in loss of ductility and fracture toughness of the material. The susceptibility to thermal aging is a function of the material chemistry, aging temperature, and time at temperature. All the cast duplex stainless steel reactor internals in the Westinghouse-designed NSSS are made from CF-8 or CF-8A materials which contain low or zero Molybdenum and are less susceptible to thermal aging than the molybdenum containing grades.

The MPS3 reactor internals contain some cast austenitic stainless steel material. Although this material is potentially susceptible to thermal aging embrittlement under prolonged exposure to elevated temperatures, the chemistry content and the service temperatures (354°F – 623°F) at MPS3 are not favorable to produce enough loss of toughness to have any significant impact on the structural integrity.

The topical report WCAP-14577, Rev. 1-A, “License Renewal Evaluation: Aging Management for Reactor Vessel Internals”, conducted an evaluation of the effects of thermal aging and concluded that the effects of thermal aging are insignificant to all of the reactor internals components and aging management of this effect is not required during an extended period of operation.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The NRC's acceptance criteria for reactor internals and core support materials are based on GDC-1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of reactor internals and core supports. DNC's review of MPS3 covered the materials' specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation. Specific review criteria are contained in SRP Section 4.5.2 and WCAP-14577.

On the basis of the review and audit of the MPS3 Reactor Vessel Internals License Renewal SER, the NRC concluded that those portions of the program for which MPS3 claimed consistency with GALL program are consistent with GALL. Furthermore NRC's review of the MPS3-specific exceptions to the GALL program found that DNC has demonstrated that the effects of aging are adequately managed so that the intended functions are maintained consistent with the current licensing basis for the period of extended operation, as required by 10 CFR 54.21(a)(3). The NRC's review of the FSAR supplement for the Aging Management Program (AMP) found that it provided an adequate summary description of the program as required by 10 CFR 54.21(d).

All SPU evaluations and discussions included in this Licensing Report addressed meeting the licensing basis for a time period of up to 54 EFPY or 60 years of service.

2.1.4.2.4 Results

The results of the potential material degradation assessment of the reactor vessel internals showed that no materials degradation issues result from the proposed SPU at MPS3. On this basis it is concluded that the new SPU environmental conditions (chemistry, temperature, and fluence) do not introduce any new aging effects on their components during 60 years of operation, nor does the SPU change the manner in which the component aging is managed by the aging management program credited in the topical report WCAP-14577, Rev. 1-A, "License Renewal Evaluation: Aging Management for Reactor Vessel Internals", and accepted by the NRC in the SER.

2.1.4.3 Conclusion

DNC has reviewed the evaluation of the effects of the proposed SPU on the susceptibility of reactor internal and core support materials to known degradation mechanisms and concludes that the evaluation has identified appropriate aging management programs to address the effects of changes in operating temperature and neutron fluence on the integrity of reactor internal and core support materials. DNC further concludes that the evaluation has demonstrated that the reactor internal and core support materials will continue to be acceptable and will continue to meet the requirements of GDC-1 and 10 CFR 50.55a following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to reactor internal and core support materials.

2.1.4.4 References

1. EPRI TR-1002884, Volume 1, "Pressurized Water Reactor Primary Water Chemistry Guidelines," Rev. 5, September 2003.

2. Kangilaski, M., "The Effects of Neutron Radiation on Structural Materials," REIC Report No. 45, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio (June 1967).

3. Robbins, R. E., et. al., "Post Irradiation Tensile Properties of Annealed and Cold Worked AISI – 304 Stainless Steel," Trans American Nuclear Society, pp 488-489 (Nov. 1967).

4. Bloom, E. E., "Mechanical Properties of Materials in Fusion Reactor First-Wall and Blanket Systems," Journal of Nuclear Materials, 85 and 86, pp 795-804 (1979).

5. PCWG-06-9, Millstone Unit 3 (NEU): Approval of Category III (for Contract) PCWG Parameters to Support a 7 percent Stretch Power Uprate (SPU) Program, April 25, 2006

Table 2.1.4-1 Estimated Maximum Fast Neutron Exposure of the MPS3 Reactor Internals

Operating Time [EFPY]	Fluence (E > 0.1 MeV) [n/cm^2] (current Design Basis)	Fluence (E > 0.1 MeV) [n/cm^2] (current, 13.8 EFPY)	Fluence (E > 0.1 MeV) [n/cm^2] (7% Uprate)
32	1.6E+23	4.48E+22	9.74E+22
54	2.7E+23	1.70E+23	1.65E+23

2.1.5 Reactor Coolant Pressure Boundary Materials

2.1.5.1 Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high pressure fluids produced in the reactor. The DNC review of RCPB materials covered their specification, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs.

The acceptance criteria for this review are:

- 10 CFR 50 Part 55a and GDC-1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed
- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents
- GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture
- GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specific conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized
- 10 CFR 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB.

Specific review criteria are contained in the SRP, Section 5.2.3, and guidance provided in Matrix 1 of RS-001 for RCPB materials. Additional guidance for PWSCC of dissimilar metal welds and associated inspection programs is contained in NRC GL 97-01 and NRC Bulletins (BL) 01-01; BL-02-01 and BL-02-02. Additional review guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from C. Grimes, NRC, to D. Walters, NEI, dated 19 May, 2000.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800) and SRP Section 5.2.3, Rev. 2.

As noted in the FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3’s pressure retaining components and component supports’ design relative to:

- 10 CFR 50.55a is described in FSAR Section 5.2.1.1, Compliance with 10 CFR 50.55a. RCS components are designed and fabricated in accordance with 10 CFR 50.55a. The actual addenda of the ASME B&PV Code applied in the original design of each component are listed in FSAR Table 5.2-1.

- GDC-1, Quality Standards and Records, is described in the FSAR Section 3.1.2.1.

  SSCs important to safety are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

  Quality standards applicable to safety related SSCs are generally contained in codes such as the ASME B&PV Code. The applicability of these codes is specifically identified throughout this report and is summarized in FSAR Section 3.2.5. FSAR Section 17.1 provides direct reference to the Quality Assurance Program established to provide assurance that safety related SSCs satisfactorily perform their intended safety functions. The procedures for generating and maintaining appropriate design, fabrication, erection, and testing records are contained within the referenced documents.

- GDC-4 is described in the FSAR Section 3.1.2.4, Environmental and Missile Design Bases.

  SSCs important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCA's. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

  SSCs important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in the FSAR, Section 3.2.5.

- GDC-14, Reactor Coolant Pressure Boundary (RCPB), is described in FSAR Section 3.1.2.14.

  The RCS boundary is designed to accommodate the system pressures and temperatures attained under all modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits (See FSAR Section 3.9). RCPB materials, selection, and fabrication techniques ensure a low probability of gross rupture or abnormal leakage.

  In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions, such as seismic and pipe rupture, as discussed in FSAR Sections 3.6 and 3.7. The system is protected from overpressure by means of pressure relieving devices as required by applicable codes (See FSAR Section 5.2.2).

  The RCS boundary has provisions for inspection, testing, and surveillance of critical areas to assess the structural and leak tight integrity (FSAR Section 5.2.2). For the RV (FSAR Section 5.3), a material surveillance program conforming to applicable codes is provided.

- GDC-31, Fracture Prevention of Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.31.

  Close control is maintained over material selection and fabrication for the RCS to assure that the boundary behaves in a non-brittle manner. The RCS materials exposed to the coolant are corrosion resistant stainless steel or Inconel. The NIL ductility reference temperature of the RV structural steel is established by Charpy V-notch and drop weight tests, in accordance with 10 CFR 50, Appendix G.

  The fabrication and quality control techniques used in the fabrication of the RCS are consistent with those used for the RV. The inspection of RV, pressurizer, piping, pumps, and steam generator are governed by ASME Code requirements.

The MPS3 RCS is described in FSAR Section 5.1. The RCS and the RCPB are shown in FSAR Figure 5.1-1. RCPB components include the following equipment, which is designed to the ASME B&PV Code, Section III, Class 1 requirements:

- Reactor Vessel, including CRDM housings
- Steam Generators (RC side)
- Pressurizer (and surge line attached to one of the RC loops)
- RCPs
- PRT
- Safety and Relief Valves
- Reactor Coolant Piping
- Loop isolation valves
- Interconnecting piping, valves and fittings between the principal components described above
- The piping, fittings and valves leading to connecting auxiliary or support systems

The RCS consists of four similar heat transfer loops connected in parallel to the RPV. Each loop contains a RCP and a SG. In addition, the system includes a pressurizer, a pressurizer relief tank, interconnecting piping, valves and instruments necessary for operational control.

The MPS3 RCPB materials are addressed in FSAR Section 5.2.3 and Table 5.2-3. The RCPB materials were selected for the expected environmental and service conditions. They have been designed, procured, fabricated, and inspected to satisfy the requirements of ASME Section III, Class 1.

The MPS3 RCPB materials were evaluated for continued acceptability to support plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3”, dated August 1, 2005, documents the results of that review. NUREG-1838, Sections 2.3B.1.1 and 3.1B are applicable to the reactor vessel and connected components.

2.1.5.2 Technical Evaluation

2.1.5.2.1 Introduction

This section of the report summarizes the evaluations, and their results, of the potential materials degradation issues arising from the effect of the MPS3 SPU on the performance of reactor coolant pressure boundary component materials.

The SPU evaluation assessed the potential effect of changes in the RCS chemistry (impurities), pH conditions, and SPU service temperatures on the integrity of primary component pressure boundary materials during service. The evaluation includes:

- An assessment of the potential effect of water chemistry changes on the general corrosion (wastage) of carbon steel components, SCC of system austenitic stainless steel materials, and the management strategy of any associated issues.
- An assessment of the effect of change in the service temperature on PWSCC of Alloy 600/182/82 nickel base alloys, thermal aging of CASS materials, and the management strategy of any associated issues.

These assessments are discussed in the following subsections.

2.1.5.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Proposed SPU Service Conditions

A review of the SPU design parameters indicates that the following changes in the RCS chemistry and service temperature conditions (Section 1.1, Table 1-1) occur during operations after the SPU implementation:

- The SPU reactor coolant lithium/boron chemistry program is coordinated such that a target pH range between 7.11 and 7.20 is maintained with an initial maximum target lithium level of 3.5 ppm. The lithium level is then decreased gradually during the fuel cycle as the boron diminishes, thus maintaining a target pH value of 7.20 through the end of the fuel cycle.
- A maximum increase ΔT in the peak steady state service temperature of 4.3°F at the reactor vessel hot leg location and an increase ΔT in service temperature of 0.5°F at the reactor vessel cold leg and BMI penetration locations will occur due to the SPU. This is summarized in Table 2.1.5-1.

2.1.5.2.3 Description of Analyses and Evaluations

The effect of change in service conditions (temperature and water chemistry) due to the proposed SPU on the performance of the reactor coolant pressure boundary materials is discussed in the following paragraphs.

General Corrosion/Wastage of Carbon Steel Components

The MPS3 SPU reactor coolant lithium/boron program is coordinated such that an elevated 7.2 pH value is maintained during the fuel cycle (up to 1500 ppm boron) while maintaining a maximum lithium level of less than or close to 3.5 ppm. Experience with operating plants as well as with the guidelines provided by EPRI (PWR Primary Water Chemistry Guidelines: Vol. 1, Rev. 5, EPRI Palo Alto CA: 2003, TR-1002884) suggest that increasing initial lithium concentrations of up to 3.5 ppm with controlled boron concentrations to maintain pH values between 6.9 to 7.4 does not produce any undesirable material integrity issues.

The MPS3 Boric Acid Corrosion Control (BACC) program is discussed in Section B2.1.6 of the WCAP-14575-A, License Renewal Evaluation: Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components. The NRC reviewed the MPS3 BACC program and found the MPS3 RAI responses acceptable since MPS3 expanded the BACC program scope to become consistent with the GALL report, incorporated lessons learned from Davis-Besse, and addressed NRC generic communications. On the basis of its review and audit findings the NRC concluded that MPS3 demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3). MPS3 performed examinations for evidence of leakage and wastage in response to the revised NRC Order EA-03-008 and EPRI Report MRP-139 in lieu of NRC GL 97-01 and NRC Bulletins 01-01, 02-01, and 02-02, with no evidence of leakage or wastage noted.

SCC of Austenitic Stainless Steels

The two degradation mechanisms that are operative in the pressure boundary austenitic stainless steel (base and weld) materials in the RCPB are IGSCC and TGSCC. The occurrence of IGSCC in austenitic stainless steel typically requires the presence of a sensitized microstructure and a significant level of dissolved oxygen. The prerequisites for TGSCC in austenitic stainless steels include a significant level of dissolved oxygen and some level of halogens (such as chlorides). If dissolved oxygen levels are high, TGSCC can occur in annealed stainless steels at chloride levels below the maximum level permitted during operation by the EPRI PWR primary water chemistry guidelines.

The SPU reactor coolant lithium/boron program is coordinated such that an elevated 7.2 pH value is maintained during the fuel cycle (up to 1500 ppm boron) while maintaining a maximum lithium level of less than or close to 3.5 ppm.

The chemistry changes resulting from the SPU do not involve introduction of any of these contributors so that no effect on material degradation is expected in the stainless steel components as a result of the SPU. There is a negligible increase in material degradation due to the increased temperature change.

Alloy 600/82/182 Components at MPS3

- Alloy 600 and Alloy 82/182 weld deposit are present in the MPS3 RCS at the following locations:

  1. Reactor vessel upper head CRDMs and head vent penetrations. The penetrations are Alloy 600, welded to the ID of the head with partial penetration welds using 82/182 weld deposit.

  2. Pressurizer surge, spray, safety, and relief nozzle 82/182 butter welds.

3. Alloy 600 BMI nozzles and Alloy 82/182 J-groove welds.
4. Steam generator channel head drain Alloy 600 nozzles and 82/182 welds.
5. Reactor vessel flange leakage monitor tube.
6. Steam generator tubesheet cladding (either explosive clad or weld deposit).
7. Steam generator tube-to-tubesheet welds (autogenous).
8. Steam generator partition plate: stub runner/divider plate.
9. Alloy 182 steam generator stub runner to divider plate weld.
10. Alloy 182 steam generator partition plate to tubesheet cladding weld; partition plate to channelhead weld.
11. Alloy 600 steam generator primary nozzle closure ring (one or two piece rings).
12. Alloy 182 steam generator closure ring weld(s).
13. Alloy 600 reactor vessel core guide lugs and 82/182 welds.
14. Alloy 82/182 reactor vessel core guide lug shell cladding.

PWSCC of Nickel Base Alloy 600/82/182 Materials

The major form of degradation affecting Alloy 600 and weld metals Alloy 182/82 exposed to primary coolant has been PWSCC which has occurred in numerous Alloy 600 parts/components and Alloy 182/82 weldments in PWRs world-wide. Through-wall cracks have resulted in primary coolant leakage from numerous nozzles and weldments while in-service inspections have discovered part-through-wall cracks in other nozzles and welds. Stress corrosion cracking occurs when a susceptible material condition has a significant tensile stress and is exposed to an aggressive environment. Alloy 600 and its weld metals, Alloys 182/82, are susceptible to a PWSCC over a range of material conditions and properties. Stresses, including residual stresses from fabrication and welding processes and operational stresses, are frequently sufficiently high to cause PWSCC. High temperature primary water is aggressive enough to cause PWSCC of highly stressed Alloy 600 and its weld metals.

Extensive laboratory test data and field experience indicate that PWSCC is a thermally activated process that can be described by an Arrenhius relationship:

$$\text{Time-to-Crack, } t_i = 1/\text{initiation Rate} = A\sigma^{-n}\exp(-Q/RT)$$

where:

A=a material constant, that includes the effect of microstructure

σ =stress, the combination of operational and residual stresses n=exponent on stress, which laboratory data indicates is approximately -4

Q=activation energy (50 kcal/mole for PWSCC initiation)

R=gas constant (1.103×10^{-3}kcal/mole °R)

T=absolute temperature (°R, °F+459.7).

For the SPU at MPS3, the most important variable in the above expression is temperature because the material condition and properties and the residual stress levels for the various Alloy 600 components and welds were established by the original material processing and component fabrication. Minor temperature changes, such as those accompanying SPU, will not have a significant effect on the material conditions or stresses. Thus, temperature is the only parameter that needs to be considered for the SPU PWSCC evaluation. The relationship indicates that the greatest impact will occur at those locations with the highest temperature.

The location in the reactor coolant system with the highest temperature is the pressurizer, but the SPU will not have any effect on the pressurizer temperature; thus, the Alloy 182/82 weldments in the pressurizer will not be impacted by the SPU.

The reactor vessel outlet nozzles experience hot leg temperatures and, since hot leg temperatures will increase from approximately 618.3°F (an increase of a maximum of 4.3°F), the remaining lifetimes before PWSCC initiation will be reduced. The relationship above was used with the before and after temperatures cited to estimate the effect of the temperature increase. The estimated effect is a reduction in the remaining nozzle lifetimes before PWSCC initiation of approximately 18 percent.

The bottom mounted instrument nozzles in the reactor vessel bottom head and the control rod drive mechanism (CRDM) nozzle in the reactor vessel closure head at MPS3 experience temperatures that are approximately at the reactor vessel inlet (cold-leg) temperature. The SPU will increase the cold-leg temperature by a maximum of 0.5°F. Using the maximum cold-leg temperature values of Table 2.1.5-1 and the above relationship indicates that the 0.5°F increase may reduce the remaining PWSCC lifetime of these nozzles by approximately 2 percent, which is negligible.

Although the lifetime reductions of the reactor vessel outlet nozzles and the BMI and CRDM nozzles are considered minor, MPS3 will continue inspecting these nozzles and weldments in accordance with industry guidelines and regulatory requirements. Specifically, MPS3 will inspect the reactor vessel inlet and outlet nozzles in accordance with MRP-139, Tables 6-1 and 6-2, which require volumetric inspection of hot leg nozzle welds every 5 years and visual inspection every refueling outage unless mitigative actions are taken. Similarly, MPS3 will be inspecting the CRDM nozzles in accordance with Revision 1 of NRC Order EA-03-009, or the ASME Code when it is changed to incorporate CRDM nozzle inspection requirements. Also, MPS3 is currently inspecting BMI nozzles visually every refueling outage.

Thermal Aging

Thermal aging of cast stainless steel can lead to precipitation of additional phases in the ferrite and growth of existing carbides at the ferrite/austenitic boundaries that can result in loss of ductility and fracture toughness of the material. The susceptibility to thermal aging is a function of the material chemistry, aging temperature and time at temperature.

The thermal aging of CASS materials associated with RCS loop piping (SA-351 CF8A) and the RCP nozzles and safe-ends (SA-351 CF8) operating under SPU conditions given in Section 1.1 are bounded by analyses completed for license renewal.

Impact of SPU on the Renewed Plant Operating License Evaluations and License Renewal Programs

On the basis of the review and audit of the MPS3 Reactor Coolant Pressure Boundary materials License Renewal SER, the NRC concluded that those portions of the program that MPS3 claimed to be consistent with the GALL program were found to be consistent with the GALL. Furthermore NRC's review of the exceptions to the GALL program found that MPS3 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

On the basis of the above, the NRC further concluded that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of subcomponents subject to an AMR, such that there is a reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

The evaluation of the small increase in temperature on the effectiveness of the aging management programs was evaluated and determined that the program will remain adequate.

All SPU evaluations and discussions included in this LR section, addressed meeting the licensing basis for a time period of up to 54 EFPY or 60 years of service.

2.1.5.2.4 Results

Based on the results of the assessment of the potential materials degradation issues resulting from the proposed SPU at MPS3, It is concluded that:

- No new material degradation issues of carbon steel boric acid corrosion are expected due to the SPU water chemistry.
- The risk for PWSCC of the Alloy 600/82/182 Reactor Vessel Head Penetrations and BMI Penetrations does not change due to the negligible increase in the service temperature of the Vessel Head and BMI penetrations. The slight increase in T_{HOT} (Reactor Vessel hot leg nozzles) and T_{COLD} (BMI, Reactor Vessel Head and cold leg nozzles) will shorten the time to PWSCC for these components. However, the lifetime reductions of the reactor vessel outlet nozzles and the BMI and CRDM nozzles are considered minor. MPS3 will continue inspecting these nozzles and weldments in accordance with industry guidelines and regulatory requirements.
- The effect of a small increase in the hot leg temperature on the thermal aging of piping and welds was assessed. MPS3 follows the WOG recommended AMP to address the impact of

thermal aging embrittlement on the LBB evaluations for the period of extended operation. The SPU will not affect any changes to the AMP.

- The NRC's review (MPS3 License Renewal SER) concluded that the MPS3 GALL process identified in the License Renewal Application (LRA) is consistent with the GALL Report (NUREG-1801) and that MPS3 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3). The SPU will not cause a change to the MPS3 aging management.
- The chemistry changes resulting from the SPU do not involve introduction of any of the contributors to SCC of austenitic stainless steel, therefore no material degradation is expected in the stainless steel components as a result of the SPU.

The results of the reactor coolant pressure boundary material degradation assessment showed that no new materials degradation issues will result from the proposed SPU at MPS3. On this basis it is concluded that the new SPU environmental conditions will not introduce any new aging effects on their components during 60 years of operation, nor will the SPU change the manner in which the component aging are managed by the aging management program credited in the LRA and accepted by the NRC in the SER.

2.1.5.3 Conclusion

DNC has reviewed the evaluation of the effects of the proposed SPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the evaluation has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of RCPB materials. DNC further concludes that the evaluation has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed SPU and will continue to meet the requirements of GDC-1, GDC-4, GDC-14, GDC-31, 10 CFR 50, Appendix G, and 10 CFR 50.55a. Therefore, DNC finds the proposed SPU acceptable with respect to RCPB materials.

Table 2.1.5-1
Summary of Service Temperature Changes in the RV Hot and Cold Legs Due to the Proposed 7% SPU

Core Power Level (MWt)	Location	Temperature (°F)	Maximum Change in the Steady State Peak Temperature Due to Uprating (ΔT °F)
3411 (CLTP)	RV Hot Leg	618.3	
3411 (CLTP)	RV Cold Leg (& RVH & BMI Penetrations)	555.9	
3650 (7% SPU)	RV Hot Leg	605.6 - 622.6	+4.3
3650 (7% SPU)	RV Cold Leg (& RVH & BMI Penetrations)	537.4 - 556.4	+0.5

2.1.6 Leak-Before-Break

2.1.6.1 Regulatory Evaluation

Leak-before-break (LBB) analyses provide a means for eliminating from the design basis the dynamic effects of postulated pipe rupture for a piping system. NRC approval of LBB analysis for a plant permits the licensee to (1) remove protective hardware along the piping system (i.e., pipe whip restraints and jet-impingement barriers); and (2) redesign pipe-connected components, their supports, and their internals. DNC's review of LBB covered

1. Direct pipe failure mechanisms (e.g., water hammer, creep damage, erosion, corrosion, fatigue, and environmental conditions).

2. Indirect pipe failure mechanisms (e.g., seismic events, system overpressurizations, fires, flooding, missiles, and failures of SSCs in close proximity to the piping).

3. Deterministic fracture mechanics and leak detection methods.

The acceptance criteria are based on

- GDC-4, insofar as it allows exclusion of dynamic effects of postulated pipe ruptures from the design basis.

Specific review criteria are contained in the draft SRP, Section 3.6.3, and the guidance provided in Matrix 1 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), Section 3.6.3, Draft Rev. 3.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, these sections discuss the adequacy of MPS3 design relative to conformance to

- GDC-4, Environmental and Missile Design Bases, is described in FSAR Section 3.1.2.4.

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

A LBB analysis was performed for the MPS3 RCS Primary Loop. The analysis for MPS3 is documented within topical report WCAP-10587, dated June 1984. In a letter dated September 12, 1984, on behalf of MPS3, a request for an exemption from a portion of the requirements of GDC-4 was submitted to the NRC.

In a letter from B.J. Youngblood to J.F. Opeka, dated July 24, 1985, regarding Amendment 12 to MPS3 Construction Permit CPPR-113, the NRC issued a partial exemption to MPS3 regarding certain aspects of GDC-4. The exemption permitted MPS3 to eliminate the installation of protective devices and the consideration of the dynamic effects and the loading conditions associated with postulated pipe breaks in the four primary loops in the Millstone 3 primary coolant system for the period ending at the completion of the second refueling outage.

Subsequent to this amendment/partial exemption, as discussed in FSAR Section 3.1.2.4, LBB became an accepted methodology by the NRC when it published a final rule in the Federal Register, Volume 51, No. 70, dated April 11, 1986, modifying GDC-4 to allow the use of LBB technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in PWRs. This rule obviates the need for the above exemption.

The MPS3 LBB analysis included in WCAP-10587 was evaluated during plant license renewal for continued acceptability. NUREG-1838, Safety Evaluation Report for Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838, Section 4.7B.3, Leak-Before-Break, contains the NRC evaluation related to the MPS3 LBB analyses.

2.1.6.2 Technical Evaluation

2.1.6.2.1 Introduction

The current structural design basis of the MPS3 includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. The purpose of this Licensing Report section is to describe the evaluations performed to demonstrate that the elimination of these breaks from the structural design basis continues to be valid following implementation of the SPU, and that primary loop piping for which DNC credits LBB continues to comply with the requirements of GDC-4, the Rev. 0 SRP, Section 3.6.3, and NUREG-1061, Volume 3.

To demonstrate the validity of elimination of primary loop pipe breaks, the following objectives had to be achieved:

- Demonstrate that margin exists between the “critical” flaw size and a postulated flaw that yields a detectable leak rate.
- Demonstrate that margin exists between the leakage through a postulated flaw and the leak detection capability.
- Demonstrate that margin exists on the applied load.
- Demonstrate that fatigue crack growth is negligible.

These objectives were met in the current LBB analysis.

To support the SPU at MPS3, the current LBB analysis was evaluated to address the proposed SPU conditions.

2.1.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The loadings, operating pressure, and temperature parameters for the SPU were used in the evaluation.

The parameters, which are important in the evaluation are the piping forces, moments, normal operating temperature, and normal operating pressure. These parameters were used as input in the evaluation. The normal SPU operating temperature range and normal operating pressure conditions are provided in Table 1-1 of Section 1.1.

Acceptance Criteria

The LBB acceptance criteria are based on the Draft SRP, Section 3.6.3, and NUREG-1061, Volume 3. The LBB recommended margins are as follows:

- Margin of 10.0 on leak rate
- Margin of 2.0 on flaw size
- Margin of 1.0 on loads (using faulted load combinations by absolute summation method)

2.1.6.2.3 Description of Analyses and Evaluations

Primary Loop Piping

Westinghouse performed a plant-specific LBB analysis for the MPS3 primary loop piping. The results of the analysis were documented in WCAP-10587 (Reference 1).

The WCAP-10587 analyses formed the basis for the SPU analyses. The primary loop piping dead weight, normal thermal expansion, and SSE, and pressure loads due to the SPU conditions were employed. The SPU normal operating temperature range and pressure were used in the evaluation. The evaluation results demonstrated that all the LBB recommended margins for the primary loop piping continue to be satisfied for the SPU conditions. The recommendations and criteria proposed in NUREG-1061, Volume 3, and the Draft SRP, Section 3.6.3, are incorporated in the evaluation.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the LBB analysis and its assumptions. The evaluations performed for aging management concerning material fracture toughness remain valid for the SPU conditions.

2.1.6.2.4 Results

The evaluation results demonstrated the following:

- Leak Rate – A margin of 10.0 exists between the calculated leak rate from the leakage flaw and the leak detection capability of 1 gpm.
- Flaw Size – A margin of 2.0 or more exists between the critical flaw size and the leakage flaw size.
- Loads – A margin of 1.0 exists on loads (using faulted load combinations by absolute summation method).

The evaluation results demonstrated that the LBB conclusions provided in current LBB analysis for MPS3 remain unchanged for the SPU conditions.

It was therefore concluded that the LBB acceptance criteria continue to be satisfied for the MPS3 primary loop piping at the SPU conditions. All the recommended margins continue to be satisfied and the conclusions shown in the current LBB analysis remain valid. It was therefore concluded that the dynamic effects of primary loop pipe breaks need not be considered in the structural design basis of the MPS3 at the SPU conditions.

Fully-aged fracture toughness properties of the cast stainless steel materials, considering the thermal aging degradation, were used in the LBB evaluation. Therefore, MPS3 primary loop piping LBB evaluation for SPU condition is also valid for a 60-year operating license (license renewal).

2.1.6.3 Conclusion

DNC has reviewed the evaluation of the effects of the SPU conditions on the LBB analyses for MPS3 and determined that the changes in the primary system pressure and temperature range and the associated effects on the LBB analysis have been adequately addressed. DNC further determined that the evaluation demonstrated that the LBB analysis will continue to remain valid following implementation of the SPU and that primary loop piping that credit LBB will continue to meet the MPS3 current licensing basis requirements with respect to GDC-4. Therefore, DNC finds the SPU acceptable with respect to LBB for MPS3.

2.1.6.4 References

1. WCAP-10587, Technical Bases for Eliminating Large Primary Loop Pipe Rupture as a Structural Design Basis Millstone Unit 3, June 1984.

2.1.7 Protective Coating Systems (Paints) Organic Materials

2.1.7.1 Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides, and they also provide wear protection during plant operation and maintenance activities. The review covered protective coating systems used inside the containment for their suitability for and stability under DBLOCA conditions, considering radiation and chemical effects.

The acceptance criteria for this review are

- 10 CFR 50, Appendix B, which states quality assurance requirements for the design, fabrication, and construction of safety-related structures, systems, and components.
- RG 1.54, which provides guidance on application and performance monitoring of coatings in nuclear power plants.

Specific review criteria are contained in SRP Section 6.1.2.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981(NUREG-0800), SRP Section 6.1.2, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 Station design relative to conformance to

- 10 CFR 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, is described in FSAR Section 17.1, Quality Assurance Program Topical Report, as follows:

  A comprehensive Quality Assurance Program has been developed to assure conformance with established regulatory requirements, set forth by the Nuclear Regulatory Commission, and accepted industry standards. The participants in the QAP assure that the design, procurement, construction, testing, operation, maintenance, repair, and modification of nuclear power plants are performed in a safe and effective manner. The QAP Description Topical Report complies with the requirements set forth in 10 CFR 50, Appendix B, and is responsive to NUREG-0800, which describes the information presented in the Quality Assurance Section of the Safety Analysis Reports for nuclear power plants. The QAPD Topical Report is submitted periodically to the NRC in accordance with 10 CFR 50.54(a).

  In a letter dated November 12, 1998, from M. L. Bowling, Jr., NNECO, to the NRC, MPS3 provided the response to Generic Letter 98-04, “Potential For Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment.” As addressed in this letter, the requirements of 10 CFR 50, Appendix B, are implemented through specification of appropriate technical and quality requirements for the Service Level I coatings program, which includes ongoing maintenance activities.

- RG 1.54, Revision 0, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants, is described in FSAR Table 1.8-1 (equipment in the BOP scope), FSAR Table 1.8N-1 (equipment in the NSSS scope), and FSAR Section 6.1.2, as follows:

1. Prior to December 14, 2005, MPS3 complied with RG 1.54, Rev. 0, as follows:

a. Equipment in BOP (non-NSSS) scope (FSAR Table 1.8-1):

Quality Assurance Program recommendations stated in RG 1.54 are followed except for the inspection defined in Section 6.2.4 of ANSI N101.4-1972, Quality Assurance for Protective Coatings Applied to Nuclear Facilities. Inspection is in accordance with ANSI N5.12-1974, Section 10, Inspection for Shop and Field Work. Testing of coating materials is performed in accordance with ANSI N101.2, Protective Coatings for Light Water Nuclear Reactor Containment Facilities, or ASTM D3911, Standard Test Methods for Evaluating Coatings Used in Light-Water Nuclear at Simulated Design Basis Accident Conditions, as noted in FSAR Section 6.1.2.1.

The following clarification is provided in Table 1.8-1:

Compliance will not be invoked for equipment of a miscellaneous nature and all insulated surfaces. Due to the impracticability of imposing Regulatory Guide requirements to the standard shop process used in painting valve bodies, handwheels, electrical cabinetry and control panels, loudspeakers, emergency light cases and other miscellaneous equipment, the Regulatory Guide will not be invoked for these items since the total surface area for such items is relatively small when compared to the total surface area for which the requirements are imposed.

b. Equipment in NSSS scope (FSAR Table 1.8N-1):

Table 1.8N-1 of FSAR describes compliance for equipment in NSSS scope. The Westinghouse NSSS equipment located in the Containment building is separated into four categories to identify the applicability of this Regulatory Guide to various types of equipment. These categories of equipment are as follows:

Category 1 - Large equipment

Category 2 - Intermediate equipment

Category 3 - Small equipment

Category 4 - Insulated/stainless steel equipment

A detailed discussion of compliance with RG 1.54 for each of these categories of equipment is contained in Table 1.8N-1.

Additionally, FSAR Section 6.1.2.2 provides additional discussion on compliance with RG 1.54. FSAR Table 6.1-3 lists the total estimated quantities of painted surface area inside containment. Protective coatings for use in the reactor containment have been evaluated as to their suitability in post-DBA conditions. Tests have shown that the epoxy and modified phenolic systems are acceptable for inside containment use. These evaluations (WCAP 7198L, WCAP 7825, Keeler and Long Report 78-0810-1) considered resistance to high temperature and chemical conditions anticipated during a post-DBA, as well as high radiation resistance. Further compliance information concerning Westinghouse supplied equipment has been submitted and accepted by the NRC (letter dated April 27, 1977, to C. Eicheldinger from C. J. Heltemes, Jr.).

2. Current compliance is as described in the QAPD Topical Report.

   Appendix C of the QAPD describes compliance with RG 1.54 as follows:

   This Regulatory Guide endorses ANSI N101.4-1972. The commitment to this Regulatory Guide during construction and earlier operations was site specific as listed in the approved SAR or License for each Company nuclear facility. The Company commits to the QA requirements of this Regulatory Guide and Standard for design and construction activities. Applicability and implementation of this guide, including quality inspection requirements, for modifications will be determined as needed, by a qualified engineer.

As addressed in FSAR Section 6.1.2.1, the approximate quantities of protective coatings used within the primary containment are identified in Table 6.1-3. These coatings have been tested to demonstrate that they remain intact on the surface to which they are applied during postulated post-DBA conditions. Tests were performed in accordance with Section 4 of ANSI N101.2 to meet or exceed the DBA conditions described in FSAR Section 6.2. Commencing mid-cycle 6, coating materials to be applied to surfaces inside containment are tested in accordance with either ANSI N101.2 or ASTM D3911.

FSAR Table 6.1-4 lists other organic materials used in the primary containment and their approximate quantities. These materials include

- Polyester varnish used in motor electrical insulation

- Silicone foam used in penetration sealing
- Petroleum-based hydraulic oil/lubricating oil
- EPR hypalon cross-linked polyethylene used in electrical cable insulation
- Charcoal used in filters

As addressed in FSAR Section 6.1.2.3, these materials have been selected because they have adequate resistance to anticipated radiation exposure and there is no significant degradation of their properties under a normal operating environment as well as under a post-DBA environment.

In a letter dated September 13, 2004, the NRC issued GL 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors." The generic letter identified a potential susceptibility of recirculation flow paths and sump screens to debris blockage. In a letter dated September 1, 2005, DNC provided a response to the requested information in GL 2004-02. The following activities related to modifications to the containment sump and the MPS3 ECCS recirculation functions under post-accident debris loading conditions have been completed. Therefore, MPS3 is in compliance with the regulatory requirements listed in GL 2004-02:

1. Modifications to the containment sump as a result of the analysis required by GL 2004-02 are complete; however, the general configuration of the MPS3 containment recirculation sump will remain similar to the current design.

2. DNC submitted and obtained NRC approval for a license amendment request to change the actuation method and the start time of the RSS pumps. The only change to the previously described ECCS operation following a LOCA is for the RSS pump start to be delayed to the RWST low-low level signal (same signal which causes the RHS pumps to stop).

In addition to the evaluations described above, plant structures, systems, and equipment required were evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. Coatings are addressed in NUREG-1838, Sections 3.0.3.2.16, Structures Monitoring Program, and 3.0.3.3.3, Infrequently Accessed Areas Inspection Program.

2.1.7.2 Technical Evaluation

2.1.7.2.1 Introduction

The MPS3 Protective Coatings and Linings Program ensures that coating systems are properly applied and maintained so that coatings can perform their intended function. This program applies to all aspects of coating work classified as Service Level I. Service Level I coatings are used in areas where coating failure could adversely affect the operation of post-accident fluid systems. Since this applies to coatings used inside Containment, these coatings are considered safety-related.

An important element of the Protective Coatings and Linings Program is "condition assessment." Periodic surveillance enables identification and detection of potential problems in existing coatings systems. It also provides verification of coating integrity. Inspection and condition assessment of coating material inside Containment is performed in accordance with MPS3 Engineering Procedure, "Inspection and Condition Assessment of Coating Material on Components Within the Containment." The procedure states that it may be applied at any time; however, inspection of containment coatings should be coincident and coordinated with containment liner code inspections. The procedure indicates that the target inspection scope during each refueling outage is to perform a general walk-on of the Containment, and that a visual inspection should be performed of all readily accessible areas in Containment with particular emphasis on the following: basement equipment and floor surfaces, previously identified areas with potentially deficient conditions, and corroded base metals.

Chemical testing being done for GSI-191 is currently under evaluation by the owners group to consider the effects of chemicals present in the sump affecting strainer DP post LOCA.

2.1.7.2.2 Description of Analyses and Evaluations

The evaluation of the safety-related coatings inside Containment addresses the impact of the post-LOCA Containment environment at SPU conditions on the qualification of safety-related coatings inside Containment. Also reviewed is the impact of the SPU on other organic materials used inside Containment.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the License Renewal SER regarding coatings. As addressed in Section 2.1.7.1, coatings are addressed in License Renewal SER sections that document the aging management review results for the Structures Monitoring Program and the Infrequently Accessed Areas Inspection Program. Review results included the following:

- The NRC noted that the applicant stated in the License Renewal application that the Structures Monitoring Program takes no credit for coatings applied to external surfaces of structural members in the determination of the aging effects for the underlying materials. The Structures Monitoring Program does, however, evaluate the condition of the coatings as an indication of the condition of the underlying materials.
- The scope of the Infrequently Accessed Areas Inspection Program includes the regenerative heat exchanger room in Containment and the area between the reactor vessel and the neutron shield tank. These areas will undergo a visual inspection to identify adverse conditions, including peeling, bubbling, or flaking coatings. If degradation is identified, it will be evaluated and corrected in accordance with the corrective action program.

The SPU does not affect these aging management evaluation/review results.

2.1.7.2.3 Results

An MPS3 specification identifies specific coating materials as qualified for application to surfaces inside the MPS3 Containment. These qualifications are based on testing of the specified coating materials to simulated DBA/LOCA environmental conditions. The specification requires that all materials used in production be certified to be essentially identical to the materials actually tested. Specific attributes addressed in the test reports include the test method/standard, pressure and temperature transients, and radiation dosage.

The test reports indicate that the coatings tested were subjected to pressure transients with peak pressures of at least 67 psi. As documented in FSAR Table 6.2-4, at current conditions, the post-LOCA peak containment pressure is 38.40 psig. The post-LOCA peak containment pressure at SPU conditions is 41.33 psig. Therefore, under SPU conditions, the post-LOCA peak containment pressure continues to be enveloped by the peak pressure at which the coatings to be qualified were tested.

The test reports indicate that the coatings tested were subjected to temperature transients with peak temperatures of at least 300°F. As documented in FSAR Table 6.2-4, at current conditions, the post-LOCA peak containment temperature is 261.99°F. The post-LOCA peak containment temperature at SPU conditions is approximately 267°F. Therefore, under SPU conditions, the post-LOCA peak containment temperature continues to be enveloped by the peak temperature at which the coatings to be qualified were tested.

The test reports indicate that the respective coatings were subjected to a radiation dose of at least 4E8 Rads. At current conditions, the post-LOCA total integrated radiation dose (40-year normal plus accident) is conservatively established at 2.4E8 Rads. An analysis has determined that the post-LOCA total integrated radiation dose (60 year normal plus accident) in the Containment at SPU conditions is 2.5E8 Rads. Therefore, under SPU conditions, the post-LOCA total integrated radiation dose continues to be enveloped by the total integrated radiation dose under which the coatings to be qualified were tested.

The qualified coatings inside Containment are currently qualified for a minimum pH of 5.0 and a maximum pH of 10.5. As discussed in FSAR Section 6.2.2.2, rising sump water due to a LOCA will dissolve the TSP stored in porous baskets in the Containment structure. During the initial few minutes of RS system operation, the pH of the sump and, therefore, the spray, may be alkaline (approximately 11.0). FSAR Section 6.5.2.1 states that the quench spray contains a solution of boric acid with a pH as low as 4.4. Exposure to either RWST water with a pH of 4.4 or recirculation spray with a pH of approximately 11 at current conditions occurs for a very short time (minutes).

An analysis of the range of spray/sump pH under SPU conditions has been performed. The analysis concludes that the current evaluation for maximum and minimum spray pH (i.e., maximum pH of approximately 11.0 and minimum pH of 4.4) is not affected by the SPU. However, due to an increase in the analyzed bounding boron concentration in the safety injection accumulators, the analysis shows that the minimum sump pH is approximately 4.1 at the beginning of the transient, and that the pH remains below 5.0 for approximately 10 minutes after the start of the transient. An evaluation concludes the exposure of the qualified containment coating systems to spray at a pH of 4 for two hours will not have an adverse affect on the coating materials. Therefore, the coatings inside Containment will not be adversely affected during the short time periods when the spray/sump pH is outside the qualified range for these coatings.

As discussed in Section 2.1.7.1, the other organic materials used inside Containment, identified in FSAR Table 6.1-4, have been selected because they have adequate resistance to anticipated radiation exposure and there is no significant degradation of their properties under a normal operating environment as well as under a post-DBA environment. As discussed above, the post-LOCA parameters inside Containment (e.g., peak pressure, temperature, radiation dose) at SPU conditions are not significantly different from those at current conditions. Therefore, the organic materials identified in FSAR Table 6.1-4 remain acceptable for SPU conditions.

There has been no major coatings work (painting or recoating) performed inside Containment since the original application. Application of coatings associated with minor maintenance work or modifications is performed using qualified coatings. As discussed above, coating qualification requirements envelope SPU conditions.

2.1.7.3 Conclusion

The DNC review of the effects of the proposed SPU on protective coating concluded that (1) the impact of changes in conditions following a DBLOCA and their effects on the protective coatings have been appropriately addressed, and (2) it has been demonstrated that the protective coatings will continue to be acceptable following implementation of the proposed SPU and will continue to meet the requirements of 10 CFR 50, Appendix B. Therefore, DNC finds that the proposed SPU is acceptable with respect to protective coatings systems.

2.1.8 Flow-Accelerated Corrosion

2.1.8.1 Regulatory Evaluation

FAC is a corrosion mechanism occurring in carbon steel components exposed to flowing single- or two-phase water. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on velocity of flow, fluid temperature, steam quality, oxygen content, and pH. During plant operation, control of these parameters is limited and the optimum conditions for minimizing FAC effects, in most cases, cannot be achieved. Loss of material by FAC will, therefore, occur. DNC has reviewed the effects of the proposed SPU on FAC and the adequacy of the MPS3 FAC Program to predict the rate of loss so that repair or replacement of damaged components could be made before they reach critical thickness. The MPS3 FAC Program is based upon the MPS3 responses to NRC Bulletin 87-01 and GL 89-08, as well as the guidelines in EPRI Report NSAC-202L-R1. The CHECWORKS computer code, coupled with visual inspection and volumetric examination of FAC affected components are an integral part of the MPS3 FAC Program and are used to predict loss of material.

The acceptance criteria for the FAC Program are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC. Other guidance is provided in Matrix 1 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800).

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

A FAC Program is employed at MPS3. This program has been developed based upon NRC Bulletin 87-01, “Thinning Pipe Walls in Nuclear Power Plants,” Generic Letter 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning,” and the guidelines in EPRI Report NSAC-202L-R1, “Recommendations for an Effective Flow-Accelerated Corrosion Program.” The CHECWORKS computer code is utilized as recommended by NSAC-202L-R1 to support analysis relative to predicting the loss of material. The FAC Program is designed to ensure that flow accelerated corrosion does not result in unacceptable degradation of the structural integrity of carbon steel piping systems. The MPS3 FAC Program is an integral part of the Millstone Station Flow Accelerated Corrosion Program.

The MPS3 FAC Program was evaluated for continued acceptability for the purpose of plant license renewal. The results of that review are documented in NUREG-1838, “Safety Evaluation Report (SER) Related to the License Renewal of the Millstone Power Station, Units 2 and 3.” The FAC Program is addressed in License Renewal SER Section 3.0.3.2.8, “Flow-Accelerated Corrosion,” which concludes that there is reasonable assurance that the FAC Program adequately captures those elements required to be evaluated for FAC.

2.1.8.2 Technical Evaluation

2.1.8.2.1 Introduction

This subsection addresses the following elements of the current MPS3 FAC Program:

1. Program scope and susceptibility screening
2. Analysis method determination
3. Criteria for selection of piping components (i.e., pressure rated pipe and fittings) for inspection
4. Component re-examination frequency
5. Inspection techniques
6. Scope of inspection of piping systems
7. Comparison of predicted and measured wall thickness
8. Criteria for repair/replacement of piping components
9. Description of a recent piping component repair/replacement

1. Program Scope and Susceptibility Screening

The FAC Program applies to the detection of pipe wall thinning due to flow-accelerated corrosion of safety-related and non-safety-related carbon and low alloy steel piping systems. Piping degradation caused by other wear phenomena (e.g., cavitation, particle erosion, impingement, and general corrosion) is not specifically analyzed, but is covered through the incorporation and application of in-house and industry experience. Wear in vessels, pumps, valves, and other in-line components is included where plant and industry experience indicate a specific FAC problem.

MPS3 maintains a FAC Program Manual and associated Program Instructions that define the minimum requirements for system selection, inspection, and evaluation criteria to be utilized in the FAC Program. Methods are based on the guidelines developed by the NUMARC/NEI, EPRI, and the ASME Code. The Millstone Station FAC Program is designed to meet the industry requirement for the implementation of a program which provides systematic methods to ensure that FAC of high-energy piping systems does not lead to degradation below the code minimum required wall thickness, in order to provide reasonable assurance that the structural integrity is maintained during the operating cycle.

All plant systems are considered susceptible to FAC unless excluded by the following criteria:

- Primary Systems

  Plant primary side piping and the reactor vessel are excluded from the program.

- Content

  Superheated steam piping is not susceptible to FAC. Dry saturated steam is also considered non-susceptible to FAC. Main steam conditions which exist between the steam generator and the high pressure turbine have not demonstrated significant susceptibility, based on industry experience. However, because there is some moisture content, some inspection sampling is performed on this system on a periodic basis to confirm non-susceptibility.

- Energy Level

  Piping which carries single-phase water less than 200°F is not susceptible to significant FAC and may be excluded unless experience indicates otherwise. If significant wear is found in a related single-phase system above 200°F, the low temperature criteria is reconsidered. Heating steam systems may be excluded as they are considered “non-power generation/plant safety” systems. Lines to the condenser that are under vacuum and cannot be isolated are not excluded, as loss of condenser vacuum may result in a plant trip. There is no temperature exclusion criteria for two-phase systems.

- Piping material

  Systems fabricated from stainless steel or low alloy steel having greater than 1-1/4 percent chromium may be excluded from evaluation. This exclusion applies only to complete lines fabricated from a FAC resistant alloy. If only specific components or sections of a line have been replaced with a FAC resistant alloy, then the complete line, including the replaced components, should be analyzed. This exclusion does not apply to components or lines where other wear mechanisms, such as cavitation or impingement, have been identified.

- System usage

  Portions of susceptible systems with less than 2 percent usage are candidates for exclusion. Certain exceptions to this criterion are identified in a FAC Program Instruction (e.g., portions of piping systems with flashing flow conditions).

- Piping Which Carries Fluids Other Than Water

  Non-water systems, such as instrument air, turbine lube oil, etc., are excluded.

- Piping Which Carries Raw Water

  The high dissolved oxygen content in raw water systems, such as the service water system, inhibits FAC. Therefore, these systems are considered to be non-susceptible to FAC.

- Industry/Plant Experience

  Systems/components known to be susceptible to FAC based on industry or MPS3 experience are included in the FAC Program.

The following systems have been found to be susceptible to FAC through the screening process and are therefore included in the scope of the FAC Program:

- Main steam and reheat
- Extraction steam and turbine generator gland seal and exhaust

- Feedwater heater and MSR Vents and Drains
- Condensate
- Feedwater
- Steam generator blowdown
- Auxiliary steam

Also included within the scope of the FAC Program are the feedwater heaters, the MSRs, the moisture separator drain tanks, and the reheater drain tanks.

2. Analysis Method Determination

Large bore piping systems that are susceptible to FAC and meet the minimum criteria for effective modeling are analyzed using the EPRI computer code CHECWORKS, SFA Version 2.1. Inputs to the CHECWORKS code include heat balance information (steam cycle data), water chemistry data, piping line data, and pipe material and component data. Wear rates of piping components are obtained using the Wear Calculation feature of CHECWORKS.

The computer program “Millstone FAC SFA,” developed for Millstone by the Altran Corporation, is utilized to perform piping component structural calculations (e.g., calculation of minimum wall thickness required to satisfy code requirements), storage of data supporting FAC evaluations, and data retrieval from CHECWORKS.

Certain systems and pipe segments have usage and flow rates that cannot be accurately quantified because demand and operating conditions vary greatly or are controlled by a remote level, pressure, or temperature signal. These systems cannot be effectively modeled using CHECWORKS and are categorized as non-CHECWORKS modeled systems.

For determination of wear rates in small bore non-CHECWORKS modeled systems, ultrasonic testing UT or tangential radiography measurements are taken at selected locations, usually immediately downstream of flow orifices, steam traps, control valves, etc. The five methods commonly used for determining the wear of piping components from inspection data are: (1) Band Method, (2) Average Band Method, (3) Area Method, (4) Moving Blanket Method, and (5) Point-to-Point Method. Although methods (1) through (4) use different approaches, the total wear is the difference between an initial/baseline thickness and the minimum measured thickness. This value is divided by the inservice life of the component to determine the wear rate. In Method (5), the maximum difference between two sets of thickness data from two different examination dates are used to determine the wear rate over the component inservice life between the examination dates.

For determination of wear rates in large bore non-CHECWORKS modeled piping and components in the FAC Program, UT measurements are taken at selected locations, usually downstream of flow restrictions, expanders, valves, and where there are abrupt changes in the direction of flow such as at elbows. Total wear is measured over the life of the component using the Wear Calculation feature of CHECWORKS. The total wear is imported to the Millstone FAC Structural Calculation feature, which determines the wear rate, predicted wall thickness at next outage, and time to next inspection.

A record set of P&IDs has been color-coded to identify the following:

- Lines that are modeled in CHECWORKS
- Large bore lines (nominal outer diameter greater than 2 inches) that are included in the FAC Program, but not modeled in CHECWORKS
- Small bore lines (nominal outer diameter between ¾ inches up to and including 2 inches) that are included in the FAC Program
- Main steam system lines that are included in the FAC Program, but not modeled in CHECWORKS
- Lines with 2 percent usage or less

The color-coded P&IDs are marked to show the applicable isometric sketches, which identify the specific piping segments/components included in the FAC Program.

3. Criteria for Selection of Piping Components for Inspection

Selection of piping components for inspection is addressed in the following paragraphs:

- CHECWORKS analysis of large bore systems
- Non-CHECWORKS analysis of large bore systems
- Non-CHECWORKS analysis of small bore systems
- Consideration of plant and industry experience
- Component reinspection
- Other reviews

CHECWORKS Analysis of Large Bore Systems

Once a system is adequately represented in CHECWORKS with inspection results, a PASS 2 analysis is performed to predict FAC wear rates and remaining service life for un-inspected components (i.e., time until the minimum wall thickness required to satisfy code requirements, "t_{crit}" is reached). The PASS 2 analysis performed by CHECWORKS considers selected UT inspection data and the calculation of the line correction factor, which normalizes any differences between CHECWORKS predicted wear and that determined from UT inspection. Inspection locations are selected and prioritized based on the ranking of component life remaining to t_{crit}. (Note: At MPS3, the minimum wall thickness required to satisfy code requirements is denoted by "t_{crit}" or "t_{min}".)

Components with measured wear greater than $\pm$ 50 percent of the predicted wear are evaluated to ensure the component is properly modeled or is not subject to a wear mechanism not analyzed by CHECWORKS (e.g., wear due to liquid droplet or particle impingement).

Non-CHECWORKS Analysis of Large Bore Systems

A tabulation of historical inspection and replacement data is performed to determine prior inspection coverage on each subsystem. The FAC Site Program Owner ensures that the most susceptible components within each subsystem have been inspected, as well as locations downstream of components causing high flow velocities or turbulence (e.g. downstream of control valves and orifices).

Determination of inspection points includes the following:

- Inspection coverage of each subsystem is reviewed to ensure the most susceptible components have been inspected.
- If the most susceptible components have been previously inspected, the next highest ranked components are selected for inspection. Ranking is based on the relative FAC wall thinning rates for different piping components for both single and two phase conditions.
- Discussions with FAC Operational Review Personnel are held to determine current operational/functional parameters, in support of identification of specific locations that are highly susceptible. The operational review is a system-by-system review using the plant piping and instrumentation diagrams. FAC Operational Review Personnel (ORP) are plant personnel who are involved in the operation and maintenance of plant systems on a regular basis, including reactor operators, system engineers, and maintenance personnel. Operational Review Personnel receive training in the form of an ORP review briefing to provide an understanding of the factors which influence FAC and actions taken in the plant and industry to address the issue.
- Comparison is performed of subsystem bounding required minimum allowable wall thickness with component nominal wall thickness. Subsystems with a low margin (20 percent or less) are considered for additional inspections.

Non-CHECWORKS Analysis of Small Bore Systems

- Isometric drawings for small bore systems are reviewed to ensure adequate coverage of highly susceptible areas.
- Based on the amount of piping, the extent of coverage of susceptible areas, and previous inspection results, an engineering judgment is made as to the susceptibility of the system and the adequacy of inspection coverage.
- Additional locations for inspection are selected based on FAC experience and engineering judgment.
- Discussions with FAC Operational Review Personnel are held to determine current operational/functional parameters, in support of identification of specific locations that are highly susceptible.

Consideration of Plant and Industry Experience

Plant specific experience is taken into consideration in support of the process of identifying susceptible components for inspection. Plant historical experience includes the following:

- Documentation of UT data and required repairs/replacements for each outage.

- Reporting any findings outside of the FAC Program that are suspected to be FAC-related to the responsible FAC Site Program Owner (e.g., evidence of piping or component damage exhibiting FAC wall thinning characteristics).
- Reviews held each cycle with FAC Operational Review Personnel to provide for continued update on new unit-specific experience.
- Performance of the following activities associated with closed and low-usage boundary valves which, due to leakage, can cause FAC in lines which are screened out of scope due to low usage:
  - Identification of all valves on the listing of closed and low usage boundary valves having past leakage problems.
  - Inspection of all valves with a history of seat leakage at the next inspection interval to identify potential FAC damage.

Industry experience, INPO, EPRI, and DNC fleet experience are reviewed and applicability to MPS3 is determined, and a course of action is defined as required.

Component Reinspection

Components are scheduled for reinspection based on the following:

- Suspect/questionable inspection results which require confirmation.
- Predicted life is less than the time to the next refueling outage (i.e., prior to replacement).
- Application of a finer inspection grid for wear “mapping.”
- Baseline inspection after component repair or replacement.
- Monitoring of component wear at a specified time interval.
- Information provided by the FAC Operational Review Personnel

Components which have been inspected are re-examined at a frequency consistent with the calculated component life based on the inspection results. Re-examination is scheduled for a refueling outage preceding the predicted time when t_{min} will be reached.

Reinspection requirements based on initial inspections which were non-quantitative (e.g., visual) are determined based on the judgment of the responsible engineer.

Other Reviews

Review of MPS3 Condition Reports initiated during the cycle that may require follow-up UT exams is performed to identify additional locations for inspection.

Review of MPS3 Leak Detection Services Reports (which address acoustic testing of valves, steam traps, etc. for leak-by) is performed to validate coverage or add new examination locations as needed.

Review of UT and tangential RT examination coverage downstream of steam traps is performed to identify additional locations for inspection.

4. Component Re-examination Frequency

Components that have been inspected are re-examined at a frequency consistent with the calculated component life based on the inspection results. Re-examination is scheduled for a refueling outage preceding the predicted time when t_{min}, the minimum wall thickness required to satisfy Code requirements, will be reached.

5. Inspection Techniques

The techniques used for the performance of inspections are ultrasonic testing, RT, and visual. Ultrasonic testing is utilized to detect wall thinning and provide wall thickness data that is to be analyzed by CHECWORKS to determine wear rates. Piping may be examined using RT to identify FAC damage as specified by the FAC Site Program Owner. Radiography is an acceptable method to inspect small bore piping; it is used only as an investigative tool on large bore piping. Visual examination of large bore piping is performed when appropriate to detect FAC using established guidelines.

6. Scope of Inspection of Piping Systems

A Master Inspection List identifying inspections required for a FAC inspection interval (typically each refueling outage) is derived from a review of the following:

- CHECWORKS/FAC analysis wear trending
- Large and small bore non-CHECWORKS system component trending
- Component re-inspection
- Plant and industry operating experience
- Review of Leak Detection Services reports identifying leakage past steam traps and valves.

In addition, a report is generated of previous component structural evaluation reports that are maintained in the Millstone FAC SFA data base. This report includes all CHECWORKS modeled and non-CHECWORKS large bore and small bore components that have been previously examined, and provides component life remaining based on the wear rate calculations from prior inspections. The report also includes the next normally scheduled inspection based on the prior wear calculation and remaining life to t_{crit}. Components shown as requiring inspection are screened and then added to the Master Inspection List, if required.

The Master Inspection List is broken down into three lists:

- Large bore and small bore “on-line” pre-outage UT examinations
- Large bore and small bore “outage” UT examinations (also includes visual exams)
- Small bore “pre-outage” tangential radiography examinations

7. Comparison of Predicted and Measured Wall Thickness

Table 2.1.8-1 provides a comparison of predicted wall thickness, based on CHECWORKS wear rate results at current plant conditions, with the measured wall thickness for several piping components at current plant conditions.

Instances where CHECWORKS will significantly under predict wear are usually indicative of where the initial wall thickness values (i.e., starting wall thicknesses) are found to be much less than the nominal wall thicknesses originally used in the program. This is likely to occur at counter-bore areas of welds and where components are tapered to match up inside diameters to perform welding. Those under predictions are corrected as field data is added to the CHECWORKS program. The line correction factors for measured versus predicted wear are adjusted, in part, based on field data. Because the MPS3 CHECWORKS is a more mature program with years of field data, including wear rates from point-to-point measurements and actual field wall thickness minimum values, the predicted wear is now more accurate than when the program was originated. As a result, there have been no instances over the last few outages where CHECWORKS under predicted wear such that pipe wall thickness was found by inspection to have corroded to a thickness less than the minimum wall thickness required to satisfy code requirements.

8. Criteria for Repair/Replacement of Piping Components

Repair/Replacement Criteria for Large Bore Piping Components

For CHECWORKS modeled and non-CHECWORKS modeled large bore piping, using the inspection results, the wear rate and predicted thickness at the next refueling outage is calculated, along with the predicted life past the next refueling outage. If the predicted thickness is greater than or equal to 87½ percent of the component nominal thickness ($T_{nominal}$), the component is acceptable for continued service. The 87½" percent of $T_{nominal}$ represents the thinnest pipe wall allowed by the pipe manufacturer's tolerances (± 12½ percent $T_{nominal}$). If the predicted thickness is less than or equal to 30 percent of $T_{nominal}$, for safety-related or non-safety-related piping, the component is to be replaced or repaired. For instances when the predicted thickness is between the two extreme cases (87½" and 30 percent of $T_{nominal}$), and less than the minimum required thickness to satisfy code requirements (t_{min}), a structural evaluation is required.

The structural evaluations use the value of the calculated minimum allowable wall thickness as determined by the applicable piping codes, which for MPS3 are ANSI B31.1 and ASME Section III, Class 2 and 3. This is normally the larger of the code required minimum wall thickness for hoop stress, sustained stress (i.e., bending or dead weight plus tangential stress due pressure), upset (i.e., occasional stress), or 30 percent of $T_{nominal}$. Based on the structural evaluation, if the component meets the stress requirements for the predicted wall thickness at the end of the operating cycle, the component is acceptable for continued operation. If the structural calculated stress level cannot be justified, the component would be either repaired or replaced. Although ASME code case requirements (e.g., N-597) could be used in the structural evaluations for assessing degraded components, these alternate ASME code cases have not been used since the outages following issuance of RG 1.147, "Inservice Inspection Code Case

Acceptability, ASME Section XI, Division 1," Revision 13, dated June, 2003, as use of these Code Cases for ASME code piping is now subject to NRC review and approval.

The existing criteria for repair/replacement of large bore piping components are consistent with the guidelines in EPRI Report, NSAC-202L-R1.

Repair/Replacement Criteria for Small Bore Piping Components

Repair/replacement criteria for small-bore piping are based primarily on measured wear rate data. As discussed in above, volumetric nondestructive examinations (a combination of ultrasonic and on-line tangential radiographic examinations) are used to determine small bore component wear rates. Once wall thickness is trended to below 0.100 inch, replacement needs are identified and work orders are generated, even though the minimum required wall thickness is actually lower and the wear calculation may identify that remaining life will allow the component to be in service for several more operating cycles. Where the code minimum is greater than 0.100 inch, the code minimum value is used. The intent is to replace these components long before they reach their code minimum thicknesses where these thicknesses are relatively thin. In addition, sections of adjacent piping and or parallel lines may be replaced with FAC resistant material, if not already previously replaced.

The existing criteria for repair/replacement of small bore piping components are consistent with the guidelines in EPRI Report, NSAC-202L-R1.

9. Description of a Recent Piping Component Repair/Replacement

The following is example of a replacement during the 2005 Refueling Outage:

The expanders and section of straight pipe immediately downstream of the level control valves for the Reheater Drain Tanks 1A and 1B to the high-pressure feedwater heaters 3FWS-E1A, 3FWS-E1B and 3FWS-E1C were replaced with FAC resistant Cr-Mo material in two of the six lines. Three of the six lines had been replaced with FAC resistant Cr-Mo material during the prior outage. Based upon existing wear trending, replacement of the remaining parallel line section was not immediately required. The degradation was identified as localized erosion downstream of the level control valve. The degradation was the result of geometric conditions (i.e., the two concentric expanders in series where there appears to be significant flashing of the fluid). Even though the components were changed out to FAC resistant Cr-Mo material, limited monitoring by UT examination of these replaced sections will continue due to sensitivity to these high-pressure lines. (Note: The level control valve bodies also received weld overlay repairs).

2.1.8.2.2 Description of Analyses and Evaluations

The following topics are addressed in the evaluation of impact of the SPU on the FAC Program:

1. Comparison of calculated fluid velocities at SPU conditions with industry design guidelines

2. Evaluation of steam generator blowdown system and auxiliary steam system at SPU conditions

3. Evaluation of small bore piping at SPU conditions

4. Review of heat balance temperature data at current and SPU conditions

5. Evaluation of the MSRs, feedwater heaters, MSR drain tanks, and reheater drain tanks at SPU conditions

6. Update of the CHECWORKS model for SPU conditions

7. FAC Program requirements, methods, and criteria

8. Modifications required in support of the SPU

Since the description and results of the analyses and evaluations are interrelated, these elements of the Technical Evaluation are addressed in Section 2.1.8.2.3, Results.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

NUREG-1838, Section 3.0.3.2.8 states that the FAC Program is adequate to manage the aging effects for which it is credited. The SER concludes that the MPS3 FAC Program is consistent with the requirements of the GALL. The requirements, methods, and criteria of the existing FAC Program will continue to be implemented following the SPU; no changes to these elements are required as a result of the SPU. Evaluations of impact of the SPU on system parameters affecting FAC have been performed within the scope of the existing program Therefore, the SPU does not affect the conclusions in the License Renewal SER regarding the FAC Program, and no new aging effects requiring management are identified.

2.1.8.2.3 Results

1. Comparison of calculated fluid velocities at SPU conditions with industry design guidelines

For lines/components in the following systems a comparison was made of the calculated fluid velocities at SPU conditions with industry design guidelines as a measure of whether there is an increased potential for flow accelerated corrosion:

- Main steam, including cold reheat and hot reheat
- Extraction steam

- Condensate and feedwater
- Feedwater heater (FWH) drains, moisture separator drains, and reheater drains

Note: Various operating parameters, such as fluid temperature, steam quality, and fluid velocity have an effect on wear rate. Based on the influence a particular operating parameter has on wear rate, the change in that operating parameter due to the SPU may be the governing factor affecting the resulting wear rate of a line/component.

The majority of the line/component fluid velocities are bounded by the industry design guidelines, including Crane Technical Paper No. 410, "Flow of Fluids Through Valves, Fittings, and Pipe." The lines/components for which the calculated fluid velocities exceed the industry design guidelines are as follows:

- 20 inch feedwater pump suction lines
- 16 inch motor-driven feedwater pump discharge lines
- Control valve inlet reducer/outlet expander in the main condensate header
- All 1st, 2nd, 3rd, and 5th point FWH normal drain lines upstream of the control valve in each line
- 10 inch 4th point FWH drain pumps discharge lines
- 6 inch Reheater Drain Tank 1A normal drain lines upstream of the control valve in each line
- 8 inch and 6 inch Moisture Separator Drain Pump 1A discharge lines

The feedwater, feedwater heater drains, moisture separator drains, and reheater drain lines identified above are included in the FAC Program. Inspection/evaluation of these lines per the FAC Program will be continued after the SPU.

As addressed in Section 2.5.5.4, Condensate and Feedwater, the peak velocity of the feedwater at the inlet to the steam generators increases from 19.3 ft/sec at current conditions to 20.5 ft/sec at SPU conditions. These parameters are within the industry design guidelines.

The 1st, 2nd, 3rd, and 5th point FWHs normal drain lines downstream of the control valve in each line, and the Reheater Drain Tank 1A normal drain lines downstream of the control valve in each line carry two-phase flow. These lines are included in the FAC Program. There is no industry guideline for fluid velocities in piping carrying two-phase flow. Inspection/evaluation of these lines per the FAC Program will be continued after the SPU.

2. Evaluation of Steam Generator Blowdown System and Auxiliary Steam System at SPU Conditions

The impact of the SPU on the potential for FAC in the steam generator blowdown system and the auxiliary steam system was evaluated.

Steam Generator Blowdown System

As addressed in Section 2.1.10, the normal SG blowdown flow rate increases to approximately 43 gpm per SG at SPU conditions; the blowdown system was conservatively evaluated at

45 gpm. Periodically, a blowdown is performed for a single SG while blowdown from other SGs is isolated. The blowdown rate for a single SG increases to approximately 172 gpm for SPU conditions; the blowdown system was conservatively evaluated at 180 gpm. Using the conservative blowdown flowrates, the fluid velocities in the blowdown lines at SPU conditions are bounded by the industry design guidelines.

The steam generator blowdown system is included in the FAC Program. With the exception of a section of steam generator blowdown piping downstream of the level control valve to the condenser connection, this system has not experienced any degradation that can not be trended by the current CHECWORKS model. The components downstream of the level control valve have been replaced with FAC resistant CR-MO materials. The piping/components from the steam generator blowdown tank to the level control valve are monitored and trended for wear. However, replacement of piping or components upstream of the level control valve has not been required.

Inspection/evaluation of the blowdown lines per the FAC Program will be continued after the SPU. Input parameters to CHECWORKS do not specifically consider particles that may be carried into the SGs from higher secondary system flow rates. However, any changes that result in an increase in wear of steam generator blowdown piping due to SPU conditions would be identified by the periodic inspections of the system per the FAC Program.

Auxiliary Steam System

There are no changes in the steam supply requirements at SPU conditions for the equipment supplied by the auxiliary steam system, and the SPU does not impact the operating conditions of this system. Monitoring and inspection of the auxiliary steam system per the FAC Program will be continued after the SPU.

3. Evaluation of Small Bore Piping

The impact of the SPU on the potential for FAC in small bore piping was evaluated.

The SPU may result in increased flow rates in some small bore piping, e.g., main steam drain lines. As discussed above in Section 2.1.8.2.1, monitoring and inspection of small bore lines is based on engineering judgment and experience and discussions with FAC Operational Review Personnel. Inspection/evaluation of these lines per the FAC Program will be continued after the SPU.

4. Review of Heat Balance Temperature Data at Current and SPU Conditions

As indicated above in Section 2.1.8.2.1, piping which carries single-phase water less than 200°F is not susceptible to significant FAC and may be excluded unless experience indicates otherwise. Based on review of temperature data documented in the heat balance at current plant conditions and the heat balances at SPU conditions, there are no lines for which the temperature increases from below 200°F at current plant conditions to above 200°F at SPU conditions. Therefore, no lines are recommended to be added to the FAC Program due to the SPU based on this “energy level” criteria.

As addressed in Section 2.5.5.4, the feedwater temperature at the inlet to the steam generators increases from approximately 436°F at current conditions to approximately 443°F at SPU conditions.

5. Evaluation of the MSRs, Feedwater Heaters, MSR Drain Tanks, and Reheater Drain Tanks at SPU Conditions

An evaluation of the potential for the occurrence of FAC in the MSRs at SPU conditions was performed. The conclusion of this evaluation was that periodic visual inspection of the MSRs to monitor for FAC should be performed. Monitoring and inspection of the MSRs per the FAC Program will be continued after the SPU.

An evaluation of the potential for the occurrence of FAC in the feedwater heaters at SPU conditions was performed. Results/conclusions of this evaluation include the following:

- The 1st, 2nd, 3rd, and 5th point heater drain outlet nozzle velocities exceed HEI limits. Monitoring of these nozzles for erosion should be performed.
- Two of the three 1st point heater steam inlet nozzles are slightly undersized. The 3rd point heater steam inlet nozzle velocities exceed HEI limits. Periodic inspection of these nozzles for erosion is recommended.

6. The heater drain outlet nozzles and heater steam inlet nozzles identified above are included in the FAC Program. Examination/evaluation of these nozzles per the FAC Program will be continued after the SPU.

Monitoring and inspection of the MSR drain tanks and reheater drain tanks per the FAC Program will be continued after the SPU.

7. Update of the CHECWORKS model for SPU conditions

Prior to implementing the SPU at MPS3, the CHECWORKS model will be updated based on the SPU heat balances to reflect the SPU thermodynamic and flow conditions. A comparison of pre-SPU and post-SPU predictions will be made to determine the impact of the SPU on FAC wear rates. Additional inspection coverage will be considered for lines that indicate a significant change in predicted wear rates.

For representative components highly susceptible to FAC, Table 2.1.8-2 provides a comparison of fluid temperature, fluid velocity, quality, and wear rates as determined by the CHECWORKS Program for current plant conditions and SPU plant conditions.

8. FAC Program requirements, methods, and criteria

The requirements, methods, and criteria of the existing FAC Program (e.g., criteria for repair/replacement of piping components) will continue to be implemented following the SPU. No changes to these elements are required as a result of the SPU.

9. Modifications required in support of the SPU

For modifications required in support of the SPU, impact on the FAC Program is evaluated as part of the plant design change process. For new components and any affected existing components, satisfaction of the FAC Program inclusion/exclusion criteria following the SPU will be checked, and the affected components will be subject to program requirements based on this review.

2.1.8.3 Conclusion

DNC has reviewed the evaluation of the effect of the proposed SPU on the FAC analysis for the plant and has concluded that changes in the plant operating conditions on the FAC analysis have been adequately addressed. DNC further concludes that it has been demonstrated that the updated analyses will predict the loss of material by FAC and will ensure timely repair or replacement of degraded components following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to FAC.

Table 2.1.8-1
Comparison of Predicted and Measured Wall Thickness

Wear Rate Analysis Run Definition Name	Checworks Component Name	Component Geometry Type	Nominal Thickness in	Checworks Current Wear Rate mils/yr	Checworks Line Correction Factor	Checworks Predicted Thickness in	UT Measured Thickness in	Notes
Control Valve to Blowdown Tank	057-018	Nozzle	0.688	1.053	2.803	0.630	0.645	All components with the exception of the nozzle are chrome-moly
Blowdown Tank Drain to Control Valve	058-027	90 Elbow	0.280	1.315	1.377	0.251	0.264	
Condensate Header from 2nd Point Heater to Feedwater Pump Suction	035-007	90 Elbow	1.000	6.861	1.328	0.902	0.944	
Extraction - 2nd Point (from Main Steam & Reheat to 2nd Point Heaters)	005-051 US	Pipe	0.375	4.313	0.302	0.306	0.261	

Table 2.1.8-1
Comparison of Predicted and Measured Wall Thickness

Wear Rate Analysis Run Definition Name	Checworks Component Name	Component Geometry Type	Nominal Thickness in	Checworks Current Wear Rate mils/yr	Checworks Line Correction Factor	Checworks Predicted Thickness in	UT Measured Thickness in	Notes
Feedwater Pump to 1st Point Feedwater Heater	037-021	90 Elbow	1.531	8.745	1.123	1.418	1.423	
Feedwater Pump to 1st Point Feedwater Heater	037-009 US	Pipe	1.531	7.192	1.123	1.380	1.392	
Heater Drains Header Down-stream of Control Valve	015-022	Pipe	0.500	4.813	1.613	0.385	0.389	
2nd Point Heater Drain to 3rd Point Heater Upstream of Control Valve	017-026	Pipe	0.322	3.279	0.733	0.224	0.213	
3rd Point Heater Drain to 4th Point Heater Upstream of Control Valve	019-030 US	Pipe	0.322	4.100	0.570	0.253	0.285	

Table 2.1.8-1
Comparison of Predicted and Measured Wall Thickness

Wear Rate Analysis Run Definition Name	Checworks Component Name	Component Geometry Type	Nominal Thickness in	Checworks Current Wear Rate mils/yr	Checworks Line Correction Factor	Checworks Predicted Thickness in	UT Measured Thickness in	Notes
3rd Point Heater Drain to 4th Point Heater Downstream of Control Valve	019-036	90 Elbow	0.500	3.065	0.634	0.425	0.439	
5th Point Heater Drain to Condenser Upstream of Control Valve	514-013	Pipe	0.237	3.646	1.095	0.185	0.190	
4th Point Heater Drain to Heater Drain Pump	021-002	90 Elbow	0.375	3.436	1.097	0.341	0.355	
Heater Drain Pump to Condensate	022-051	Pipe	0.500	3.212	1.081	0.442	0.456	Most of this line has been replaced with chrome-moly
Note: Measured thicknesses were from recent outages and the “predicted thicknesses” apply to the same outage for each listed component.								

Table 2.1.8-2
A Comparison of Fluid Temperature, Fluid Velocity, Quality, and Wear Rates

Wear Rate Analysis Run Definition Name	Checworks Component Name	Component Geometry Type	Temperature (°F)		Velocity (ft/sec)		Quality		Wear Rate (mils/yr)		Impact of Power Uprate on Predicted Wear Rate (%) Change)	Notes
									Current	SPU		
			Current	SPU	Current	SPU	Current	SPU	Pass 2	Pass 2	Pass 2	
Blowdown to Control Valve	053-006	45 Elbow	544.3	544	1.229	1.228	0	0	0.004	0.004	0.0	Line is constructed of chrome-moly
	050-008 US	Pipe	544.3	544	1.229	1.228	0	0	0.001	0.001	0.0	
Blowdown From Control Valve To Blowdown Tank	050-028	Pipe	319.8	319.8	20.424	20.402	0.282	0.281	0.006	0.006	0.0	All components with the exception of the nozzle are chrome-moly
	057-018	Nozzle	319.8	319.8	8.643	8.633	0.282	0.281	1.053	1.053	0.0	
Blowdown Tank Drain To Control Valve	058-002 US	Pipe	307.4	307.4	1.212	1.213	0	0	0.960	0.959	-0.1	
	058-027	90 Elbow	307.4	307.4	2.212	1.213	0	0	1.315	1.315	0.0	
Blowdown Tank Drain From Control Valve To Condenser	058-048	Nozzle	215.8	215.6	16.363	16.253	0.097	0.097	0.766	0.767	0.1	
2nd Point Heater To Condensate Heater	033-002	90 Elbow	360.2	365.5	8.107	8.829	0	0	4.507	4.708	4.5	
	034-019	Pipe	360.2	365.5	8.107	8.829	0	0	3.898	4.071	4.4	

Table 2.1.8-2
A Comparison of Fluid Temperature, Fluid Velocity, Quality, and Wear Rates

Wear Rate Analysis Run Definition Name	Checworks Component Name	Component Geometry Type	Temperature (°F) Current	Temperature (°F) SPU	Velocity (ft/sec) Current	Velocity (ft/sec) SPU	Quality Current	Quality SPU	Wear Rate (mils/yr) Current Pass 2	Wear Rate (mils/yr) SPU Pass 2	Impact of Power Uprate on Predicted Wear Rate (%) Change) Pass 2	Notes
Condensate Header From 2nd Point Heater To Feedwater Pump Suction	035-007	90 Elbow	361.1	366.5	8.837	9.61	0	0	6.861	7.149	4.2	Impact of Power Uprate on Predicted Wear Rate
	035-024	Pipe	361.1	366.5	8.837	9.61	0	0	4.080	4.251	4.2	(% Change)
Condensate - 3rd Point Heater To 2nd Point Heater	031-004	90 Elbow	321.5	326.6	8.157	8.878	0	0	4.081	4.021	-1.5	
	031-029 US	Pipe	321.5	326.6	7.909	8.609	0	0	3.462	3.411	-1.5	
Condensate - 4th Point Heater To 3rd Point Heater Upstream Of Heater Drain Line Tee	029-003	90 Elbow	284.2	288.1	7.718	8.368	0	0	5.002	5.224	4.4	
	030-002 DS	Pipe	284.2	288.1	7.718	8.368	0	0	3.650	3.812	4.4	
Condensate - 4th Point Heater To 3rd Point Heater Downstream Of Heater Drain Line Tee	029-009	90 Elbow	277.2	281.5	8.041	8.746	0	0	3.823	4.024	5.3	
	030-011 DS	Pipe	277.2	281.5	7.797	8.48	0	0	3.243	3.414	5.3	

Table 2.1.8-2
A Comparison of Fluid Temperature, Fluid Velocity, Quality, and Wear Rates

Wear Rate Analysis Run Definition Name	Checworks Component Name	Component Geometry Type	Temperature (°F)		Velocity (ft/sec)		Quality		Wear Rate (mils/yr)		Impact of Power Uprate on Predicted Wear Rate (%) Change)	Notes
			Current	SPU	Current	SPU	Current	SPU	Current Pass 2	SPU Pass 2	Pass 2	
Condensate - 5th Point Heater To 4th Point Heater	026-004	90 Elbow	219.6	222.9	7.841	8.495	0	0	4.831	5.100	5.6	
	028-017 DS	Pipe	219.6	222.9	7.481	8.106	0	0	3.169	3.346	5.6	
Crossunder	077-026	90 Elbow	375.9	382	20.955	21.66	0.866	0.868	9.609	9.730	1.3	
	077-041 US	Pipe	375.9	382	20.794	21.503	0.866	0.868	4.246	4.298	1.2	
Extraction - 2nd P0int (From Main Steam & Reheat To End Point Heaters)	005-026	90 Elbow	369.2	375.6	38.217	39.745	0.869	0.87	6.353	6.591	3.7	
	005-051 US	Pipe	369.2	375.6	38.217	39.745	0.869	0.87	4.313	4.474	3.7	
Extraction - 5th Point (From Low Pressure Turbines To 5th Point Heaters)	014-020 US	Pipe	228.4	232.6	1.311	2.017	0.956	0.951	3.891	4.225	8.6	
	014-023	45 Elbow	228.4	232.6	0.072	0.105	0.956	0.951	2.788	3.668	31.6	
Extraction - 6th Point (From Low Pressure Turbines To 6th Point Heaters)	109-004 DS	Pipe	160.4	163.7	0.029	0.036	0.925	0.923	2.891	3.369	16.5	
	109-008	45 Elbow	160.4	163.7	0.031	0.038	0.925	0.923	4.004	4.668	16.6	

Table 2.1.8-2
A Comparison of Fluid Temperature, Fluid Velocity, Quality, and Wear Rates

Wear Rate Analysis Run Definition Name	Checworks Component Name	Component Geometry Type	Temperature (°F)		Velocity (ft/sec)		Quality		Wear Rate (mils/yr)		Impact of Power Uprate on Predicted Wear Rate (%) Change)	Notes
			Current	SPU	Current	SPU	Current	SPU	Current Pass 2	SPU Pass 2	Pass 2	
Feedwater Pump To First Point Feedwater Heaters	037-021	90 Elbow	363	368.4	17	18.49	0	0	8.745	9.085	3.9	
	037-009 US	Pipe	363	368.4	15.694	17.069	0	0	7.192	7.472	3.9	
Feedwater From Hp Feedwater Heater To Steam Generator	041-004	90 Elbow	436.4	442.7	12.069	13.15	0	0	8.606	9.664	12.3	
	039-048 US	Pipe	436.4	442.7	11.162	12.162	0	0	6.944	7.799	12.3	
Heater Drains Header Upstream of Control Valve	015-033 DS	Pipe	373.4	380.3	22.607	24.671	0	0	3.685	3.746	1.7	
	015-044	90 Elbow	373.4	380.3	8.657	9.447	0	0	3.388	3.444	1.7	
Heater Drains Header Downstream of Control Valve	015-022	Pipe	364.7	370.6	29.839	31.605	0.011	0.012	4.813	5.122	6.4	
	015-062	90 Elbow	364.8	370.7	9.803	10.863	0.011	0.012	7.244	7.707	6.4	
2nd Point Heater Drain To 3rd Point Heater Upstream of Control Valve	017-026	Pipe	328.5	334.5	15.074	16.45	0	0	3.279	3.196	-2.5	
	018-002	90 Elbow	328.5	334.5	6.668	7.276	0	0	3.219	3.218	-0.0	

Table 2.1.8-2
A Comparison of Fluid Temperature, Fluid Velocity, Quality, and Wear Rates

Wear Rate Analysis Run Definition Name	Checworks Component Name	Component Geometry Type	Temperature (°F)		Velocity (ft/sec)		Quality		Wear Rate (mils/yr)		Impact of Power Uprate on Predicted Wear Rate (%) Change)	Notes
			Current	SPU	Current	SPU	Current	SPU	Current Pass 2	SPU Pass 2	Pass 2	
2nd Point Heater Drain to 3rd Point Heater	016-026	90 Elbow	321.8	327.2	7.586	8.378	0.008	0.009	0.032	0.033	3.1	Entire line is constructed of chrome-moly
3rd Point Heater Drain to 4th Point Heater Upstream of Control Valve	019-030 US	Pipe	286.7	292.1	17.276	18.899	0	0	4.100	4.375	6.7	
	020-003	90 Elbow	286.7	292.1	7.518	8.225	0	0	4.086	4.360	6.7	
3rd Point Heater Drain to 4th Point Heater Downstream of Control Valve	019-036	90 Elbow	286.7	292.1	4.867	5.324	0	0	3.065	3.360	9.6	
	020-018 DS	Pipe	286.7	292.1	4.795	5.246	0	0	2.615	2.867	9.6	
5th Point Heater Drain to Condenser Upstream of Control Valve	514-013	Pipe	169.4	173.8	10.6	11.591	0	0	3.646	3.927	7.7	
5th Point Heater Drain to Condenser Downstream of Control Valve	514-017 US	Pipe	169.4	173.8	5.177	5.661	0	0	0.016	0.018	12.5	Entire line is constructed of chrome-moly

Table 2.1.8-2
A Comparison of Fluid Temperature, Fluid Velocity, Quality, and Wear Rates

Wear Rate Analysis Run Definition Name	Checworks Component Name	Component Geometry Type	Temperature (°F)		Velocity (ft/sec)		Quality		Wear Rate (mils/yr)		Impact of Power Uprate on Predicted Wear Rate (%) Change)	Notes
			Current	SPU	Current	SPU	Current	SPU	Current Pass 2	SPU Pass 2	Pass 2	
6th Point Heater Drain to Condenser	516-017	90 Elbow	155.2	158.4	3.105	3.4	0	0	6.480	7.118	9.8	
	516-015 DS	Pipe	155.2	158.4	1.97	2.157	0	0	2.868	3.150	9.8	
4th Point Heater Drain to Heater Pump	021-002	90 Elbow	260.8	266.3	3.285	3.598	0	0	3.436	3.782	10.1	
	021-027 US	Pipe	260.8	266.3	3.285	3.598	0	0	2.321	2.556	10.1	
Heater Drain Pump Heater Drain Line to Condensate	022-051	Pipe	261.5	267	5.412	5.928	0	0	3.212	3.536	10.1	Most of this line has been replaced with chrome-moly
Moisture Separator Drain Pump Suction/Discharge	070-011	90 Elbow	369	375.5	7.01	7.53	0	0	1.023	1.065	4.1	
	072-012 DS	Pipe	368	374.4	3.024	3.248	0	0	0.253	0.268	5.9	
Moisture Separator Reheater to MSR Drain Tank	074-093	90 Elbow	368	374.4	2.659	2.856	0	0	2.354	2.485	5.6	
	074-094	Pipe	368	374.4	2.659	2.856	0	0	1.590	1.679	5.6	
Moisture Separator Reheater Drain to Reheater Drains Tank	064-002	45 Elbow	528.4	527.6	1.93	2.019	0	0	8.513	8.824	3.7	
	065-020 DS	Pipe	528.4	527.6	1.93	2.019	0	0	6.449	6.685	3.7	

Table 2.1.8-2
A Comparison of Fluid Temperature, Fluid Velocity, Quality, and Wear Rates

Wear Rate Analysis Run Definition Name	Checworks Component Name	Component Geometry Type	Temperature (°F)		Velocity (ft/sec)		Quality		Wear Rate (mils/yr)		Impact of Power Uprate on Predicted Wear Rate (%) Change)	Notes
									Current	SPU		
			Current	SPU	Current	SPU	Current	SPU	Pass 2	Pass 2	Pass 2	
Drains From Reheater Drain Tanks Upstream of Control Valve	067-008 DS	Pipe	528.2	527.4	8.273	8.652	0.001	0.001	7.291	7.454	2.2	
	068-019	90 Elbow	528.5	527.7	3.281	3.433	0	0	4.936	5.117	3.7	
Drains From Reheater Drain Tanks Downstream of Control Valve to 1st Point Feedwater Heaters	067-016 DS	Pipe	441	448	11.982	11.362	0.13	0.12	2.327	2.594	11.5	
	067-060	90 Elbow	440.1	447.3	13.545	12.811	0.132	0.121	3.765	4.219	12.1	
Note: This table's Current and SPU flow velocities are liquid film velocities (or the wet steam velocities in the liquid layers), not the steam velocities.												

2.1.9 Steam Generator Tube Inservice Inspection

2.1.9.1 Regulatory Evaluation

SG tubes constitute a large part of the RCPB. SG tube ISI provides a means for assessing the structural and leaktight integrity of the SG tubes through periodic inspection and testing of critical areas and features of the tubes. DNC review in this area addressed the effects of changes in differential pressure, temperature, and flow rates resulting from the proposed SPU on plugging limits, possible degradation mechanisms (e.g., wear caused by flow-induced vibration), plant-specific alternate repair criteria, and redefined inspection boundaries. Acceptance criteria for SG tube ISI is based upon 10 CFR 50.55a requirements for periodic inspection and testing of the RCPB. Specific review criteria are contained in SRP Section 5.4.2.2 and other guidance identified in Matrix 1 of RS-001. Additional review guidance is contained in MPS3 TS 3.4.5 "Steam Generator Tube Integrity" for SG surveillance requirements, Regulatory Guides 1.121 for SG tube plugging limits, GL 95-03 and Bulletin 88-02 for degradation mechanisms and NEI 97-06 for structural and leakage performance criteria, all which form the basis for alternate repair criteria or redefined inspection boundaries.

Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 5.4.2.2, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

The MPS3 steam generators are designed to permit inspection of ASME Code Class 1 and 2 parts, including individual tubes as stated in FSAR Section 5.4.2.2. The inspection program complies with the ASME Code, Division 1, Section XI as required by 10 CFR 50.55a, effective January 5, 1977.

All pressure boundary materials used in the steam generator are selected and fabricated in accordance with the requirements of Section III of the ASME B&PV Code. A general discussion of material specifications is given in FSAR Section 5.2.3, with types of materials listed in Tables 5.2-2 and 5.2-3. The SG tubes are manufactured from corrosion resistant Inconel 600, a nickel-chromium-iron alloy (ASME SB-163).

The minimum requirements for ISI of steam generators are presented in MPS3 TS 3.4.5. TS surveillance 4.4.5.1 and 4.4.5.2 requires implementation of the Steam Generator Program (Reference 4), for the purpose of verifying SG tube integrity. "The Steam Generator Program" identified in TS 3.4.5 and 6.8.4.g is implemented by Dominion Nuclear Fleet Administrative procedure. Compliance with the TS ensures that the SGs remain capable of fulfilling their intended safety function through application of continued monitoring and structural assessment. The Steam Generator Program has been developed based upon the processes and performance criteria defined in NEI 97-06 (Reference 4). NEI 97-06 and its six referenced EPRI Guidelines are the documents that define the Steam Generator Program referred to in the SG Technical Specifications.

The purpose of the performance criteria is described in part below:

- Structural Integrity Performance Criterion

  Ensures steam generator tubes will maintain adequate margin against burst under the full range of normal operation or postulated accident conditions.

- Accident-Induced Leakage Performance Criterion

  Ensures that the primary to secondary leakage associated with a design basis accident does not result in exceeding 10 CFR 100 dose limits.

- Operational Leakage Performance Criterion

  Provides a defense-in-depth added margin against tube rupture under accident conditions with resulting larger margins against rupture under normal operating conditions.

TS associated with plant-specific alternate repair criteria, and redefined inspection boundaries are not included as part of the MPS3 CLB.

Application of the performance criteria as presented in the Steam Generator Program ensures a high degree of confidence that the condition of the SG "is being effectively controlled through the performance of appropriate preventive maintenance" (10 CFR 50.65, Maintenance Rule §(a)(2)). Meeting the performance criteria provides reasonable assurance that the SG tubing remains capable of fulfilling its specific safety function of maintaining RCPB integrity.

The Steam Generator Program was evaluated for plant license renewal as documented in Section 3.0.3.1.4 "Steam Generator Structural Integrity Program," of NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005. As discussed in the LR application, MPS3 has an aging management program for the SGs that implement the criteria of NEI 97-06. The results of the License Renewal evaluation indicates that ISI of the SGs will be adequately managed by the Steam Generator Program so that the intended functions of the SGs will be maintained consistent with the CLB for the period of extended operation. With the exception of eddy current examinations, the ISI requirements of ASME Section XI for SGs are included in the "ISI Systems, Components and Supports" Aging Management Program Report (Reference 7). Eddy current testing of tubes and examinations not required by Section XI (e.g., visual inspection of secondary side tube sheet after sludge lancing) are discussed in accordance with the "Steam Generator Structural Integrity" Aging Management Program Report (Reference 8).

2.1.9.2 Technical Evaluation

The structural and leakage integrity of the MPS3 steam generators is maintained in accordance with the Steam Generator Program. This program is currently in use at Millstone Station. The Steam Generator Program (Reference 1) ensures SG tube integrity through continued monitoring and maintenance of the SG tubes and testing of critical areas and features of the tubes. This Program is implemented at MPS3 via application of TS surveillance 4.4.5.1 and 4.5.5.2. The Steam Generator Program will continue to be utilized to assess SG tubing structural and leakage integrity following the change in SG operating conditions (temperature, steam pressure, steam and feedwater flow) associated with the implementation of the MPS3 SPU. This Program will continue to be utilized to provide the basis for the maintenance and inspection of the SGs following implementation of the SPU.

Input Parameters, Assumptions, and Acceptance Criteria

The SG Program (Reference 1) defines the minimum requirements for an effective SG Program. Upon implementation of the SPU, the PCWG parameters identified in Section 1.1, Nuclear Steam Supply System Parameters, will be utilized as input to the SG Program. At full power, the minimum reactor vessel outlet temperature T_{HOT} will be 605.6°F and the maximum temperature will be 622.6°F. These values for T_{HOT} are taken to represent the temperature at the inlet to the SG.

In the event of a negative change in operating T_{HOT}, there would be no exacerbation of IGA/SCC tube degradation mechanisms potentially operative in the Millstone SGs, but the increased pressure differential would have an impact on allowable degradation, i.e., condition monitoring and operational limits. The calorimetric measurement-based calculations used MPS3 plant measured calorimetric data from cycle 11 to determine NSSS performance. For T_{ave} of 587°F the expected best estimate difference is an increase of 1.7°F (615.5°F to 617.2°F). If the higher T_{ave} (589.5°F) were to be realized, the increase in T_{HOT} would be 4.2°F. Any increase in T_{HOT} would have an unfavorable impact on the initiation of IGA/SCC related damage mechanisms. In addition to the reactor vessel outlet temperature, changes for reactor coolant and steam flows and for SG feed temperatures are also listed in Table 1-1 of Section 1.1.

Description of Analysis and Evaluations

ISI of SG tubes is performed in accordance with the requirements of TS 4.4.5.1 and 4.4.5.2. Requirements for SG sample selection; inspection, frequency, acceptance criteria and reporting to the NRC are specified in TS 6.8.4.g and 6.9.1.7. The SG Program requires that an assessment of potential degradation mechanisms be performed and that applicable non-destructive examination techniques be selected for use during the ISI.

Although the process parameter changes, due to the SPU, may impact the initiation and growth rates of various degradation mechanisms, these changes are considered as part of the above Program and will be considered in the future degradation assessments.

Tube inspections are planned and implemented in accordance with the Program. The potential degradation mechanisms for the MPS3 steam generator tubes are:

- Wear at anti-vibration bars (AVB), flow distribution baffle (FDB) and at foreign objects.
- Pitting at secondary side sludge/deposits.
- Outside diameter intergranular attack (OD IGA) and stress corrosion cracking (OD SCC) within hot leg expansion transitions, secondary side sludge/deposits, row 1 and 2 U-bends, dents, tube support intersections and tube freespan sections.
- PWSSC within hot legs expansion transitions, expansion anomalies, row 1 and 2 U-bends and welded I-600 tube plugs.

After performing the ISI, a condition monitoring assessment is performed to determine if there may have been structural integrity or leakage issues during the operating interval since the previous inspection. An operational assessment is performed to ensure that structural integrity and leakage performance criteria will be met during the operating interval until the next inspection. Tubes that are not projected to meet the structural integrity and/or leakage criteria are then removed from service by plugging, or repaired using an approved method.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

While the proposed SPU conditions will change current process parameters, there are no changes being made to the SGs of a material or structural nature. The potential effects of a change in current process parameters to SPU conditions are subject to evaluation as per the existing aging management review program. No unevaluated material changes to the SGs are being made which would require a reevaluation with respect to license renewal. Therefore, no new aging effects requiring management are identified.

Results

An evaluation was conducted to assess the effects of the MPS3 SPU on steam generator tube integrity due to potential changes in temperature, flow rate and steam generator chemistry (Reference 6). MPS3 Model F SGs utilize Alloy 600 TT tubes and other design features that minimize the potential for tube degradation. Corrosion mechanisms such as PWSCC, ODSCC, pitting and denting, are influenced by increased operating temperatures. Mechanical processes such as AVB wear; fatigue cracking and foreign objects wear would be more dependent on changes in the bundle flow rates.

AVB Wear - MPS3 Model F SGs all exhibit AVB wear in varying number of affected tubes, but the cumulative plugging fraction on all SGs remain below 0.6 percent for all causes. The inspection-to-inspection AVB wear rates observed in MPS3 diminished over time. Cumulatively there are 270 (1.21 percent) tubes with identified AVB wear in MPS3 SGs. The 100 percent bobbin inspection programs conducted at each outage would detect large changes easily, and more subtle changes would be reflected in a greater variation in the AVB wear rates for the same average rate.

Baffle Plate Wear - Model F SG flow distribution baffles (FDB) have not been a frequent location for the occurrence of wear due to flow-induced vibration (FIV). Although it is noted that as with TSPs, there have been cases of FDB wear that have been conclusively related to foreign objects (Reference 6). As a potential degradation mechanism, the FIV analysis performed in support of the MPS3 SPU indicate that no significant damage is expected at the tube support plates (TSP) or at the flow distribution baffle (FDB).

Foreign Objects – Loose parts wear is most frequently found in peripheral tubes for parts too large to enter the tube bundle or in cases where foreign objects lodged between tubes. The most common elevation at which foreign objects have been detected, sighted, and removed is the top of the tubesheet; however, it is not unusual to identify from eddy current data foreign objects lodged at support plates and baffles. The plugging of about 7 tubes has been attributed to wear resulting from interaction with foreign objects in the SGs, however, additional plugging - approximately 40 additional tubes at the top of the tubesheet (TTS) and at tube support plates (TSP) - both preventive and for cause should be attributed to this degradation mechanism. There were 2 tubes plugged in the MPS3 SGs during the most recent outage as a result of foreign object wear. Analyses performed for loose parts remaining in the SGs allowed and the associated tubes to remain in service and indicated that no challenge to tube integrity was presented by the loose parts. The impact on foreign object wear due to the SPU changes in operating conditions is not expected to be significant.

Pitting – To date MPS3 has not experienced pitting as determined by the eddy current inspections performed through RF11. Although operation at a slightly higher temperature is expected to accelerate corrosion mechanisms, pitting has exhibited a preference for the cold leg tubesheet sludge zone. The MPS3 SPU changes are not expected to alter the potential for occurrence of pitting in MPS3 SGs.

OD Intergranular Corrosion – Intergranular Attack/Stress Corrosion Cracking (IGA/SCC) is a general category of degradation that incorporates two variants of secondary side intergranular corrosion. The alloy 600TT tubes in MPS3 have not experienced IGA/ODSCC after 11 cycles of operation. For IGA/ODSCC, the energy of activation is approximately 32 Kcal/mol. The increase in rate at which cracking could initiate relative to present conditions is estimated to be about 4.4 percent for the 1.7°F best estimate increase (T_{HOT} increasing from 615.5°F to 617.2°F). If the higher T_{ave} (589.5°F) were to be realized, the potential increase in T_{HOT} would be 4.2°F with a corresponding projected rate of increase of 11 percent.

Primary Water Stress Corrosion Cracking

Tubesheet Joint – The 2004 inspection of the Catawba 2 model D2 SGs revealed circumferential PWSCC in the tubesheet associated with over expansion (OXP) and bulge signal (BLG) at that location (Reference 5). (This condition was also detected in the Vogtle model F steam generators). This was the first instance of tube cracking at Catawba as well as Vogtle and the first such degradation found in Alloy 600TT tubes. In MPS3 SG A, 934 locations with OXP were examined during RF10 to identify PWSCC if present; in SG C 120 such locations were tested. Signals representative of PWSCC were not detected at either SG. Corresponding locations were examined in SG B – 115 and SG D – 292 during RF11; no cracks were identified.

Hot Leg Expansion Transitions – PWSCC has been observed in the expanded regions of tubes installed using the hardroll process. The cracking occurs at the diameter transition from the expanded section of tube to the non-expanded section of tube and at locations believed to have significant residual stress from the expansion process. Every outage, MPS3 inspects 25 percent (50 percent of two SGs) of expansion transitions. To date, no incidence of cracks have been found.

U-bend PWSCC - The small radius U-bends are high stress areas and stress corrosion cracking is driven by stress and temperature. However, the thermal treatment of the Alloy 600 TT tubing following bending reduces the residual stresses to near straight leg region levels. This manufacturing process has resulted in inservice experience essentially free from U-bend PWSCC initiation including plants that went into operation in 1983. MPS3 SGs have not experienced PWSCC after 11 cycles of operation.

For the expected best estimate difference (T_{HOT} increasing from 615.5°F to 617.2°F the 1.7°F increase yields a ratio of the corrosion rates determined from the Arrhenius equation equal to 1.07 for PWSCC; this predicts a 7 percent potential increase in the rate of PWSCC initiation at the higher temperature. If the higher T_{ave} (589.5°F) were to be realized, the potential increase in T_{HOT} would be 4.2°F with a corresponding projected rate of increase of 18 percent."

2.1.9.3 Conclusion

DNC has evaluated the effects of the proposed SPU on SG tube integrity and concludes that the evaluation has adequately assessed the continued acceptability of the plants TSs under the proposed SPU conditions and has identified appropriate degradation management inspections to address the effects of temperature, differential pressure, and flow rates on SG tube integrity. DNC further concludes that SG tube integrity will continue to be maintained and will continue to meet the performance criteria in NEI 97-06 and the requirements of 10 CFR 50.55a following implementation of the proposed SPU.

2.1.9.4 References

1. ER-AP-101, "Dominion Steam Generator Program"
2. ASME Boiler and Pressure Vessel Code, Section XI, Appendix IV, 1989, no addenda.
3. EPRI Document No. 1003138 "PWR Steam Generator Examination Guidelines": Revision 6, Requirements.
4. NEI 97-06, "Steam Generator Program Guidelines, Nuclear Energy Institute, January 2001
5. SGMP-IL-05-01, SGMP Information Letter on Catawba Unit 2 Tubesheet Degradation Issues, March 3, 2005
6. Letter NEU-07-39, Rev. 1 from W. F. Staley, Westinghouse,"MPS3 SPUP Steam generator Evaluations," to Ron Thomas, Dominion Nuclear Connecticut dated June 4, 2007
7. Aging Management Program Report – "ISI-Systems, Components and Supports"
8. Aging Management Program Report – "Steam Generator Structural Integrity"

2.1.10 Steam Generator Blowdown System

2.1.10.1 Regulatory Evaluation

Control of secondary-side water chemistry is important for preventing degradation of steam generator tubes. The steam generator blowdown system (BDG) provides a means for removing steam generator secondary-side impurities and thus, assists in maintaining acceptable secondary-side water chemistry in the steam generators. The design basis of the BDG system includes consideration of expected and design flows for all modes of operation. The DNC review covered effects of the proposed SPU on the ability of the BDG system to remove particulate and dissolved impurities from the steam generator secondary side during normal operation, including anticipated operational occurrences (main condenser in-leakage and primary-to-secondary leakage).

The acceptance criteria for the BDG system are based on

- GDC-14, insofar as it requires that the reactor coolant pressure boundary be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture and of gross rupture.

Specific review criteria are contained in SRP Section 10.4.8 and guidance is provided in Matrix 1 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800), SRP Section 10.4.8, Rev. 2. As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 Station design relative to conformance to

- GDC-14 is described in FSAR Section 3.1.2.14, General Design Criterion 14 - Reactor Coolant Pressure Boundary.

  The reactor coolant system pressure boundary is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits (FSAR Section 3.9, Mechanical Systems And Components). Reactor coolant pressure boundary materials, selection, and fabrication techniques ensure a low probability of gross rupture or abnormal leakage.

  In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions such as seismic and pipe rupture, as discussed in FSAR Section 3.6, Protection Against Dynamic Effects Associated With Postulated Ruptures Of Piping, and FSAR Section 3.7, Seismic Design. The system is protected from overpressure by means of pressure-relieving devices as required by applicable codes (FSAR Section 5.2.2, Overpressure Protection).

The reactor coolant system boundary has provisions for inspection, testing, and surveillance of critical areas to assess the structural and leaktight integrity (FSAR Section 5.2, Integrity Of Reactor Coolant Pressure Boundary). For the reactor vessel (FSAR Section 5.3, Reactor Vessel), a material surveillance program conforming to applicable codes is provided.

Additional details that define the licensing basis for the BDG system are described in the following FSAR Sections:

FSAR Section 3.6.1, Postulated Piping Failures In Fluid Systems Inside And Outside Of Containment, describes the design criteria and bases for protecting essential BDG system equipment from the effect of piping failures inside and outside of containment.

FSAR Section 6.2.4, Containment Isolation System, address features to isolate the BDG lines penetrating containment to ensure that total leakage of activity will be within design limits in the event of an accident.

FSAR Section 9.3.2, Process Sampling and FSAR Table 9.3-1, Sample Points – Reactor Plant, states BDG sampling line design details.

FSAR Section 10.4.8, Steam Generator Blowdown, describes the BDG system design basis including system description and safety evaluation.

FSAR Section 11.2.2.3, Other Systems Discharging Radioactive Liquid Waste, addresses BDG discharge base cases.

The BDG system was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005 documents the results of that review. NUREG-1838 Sections 2.3B.4.4 and 3.4B are applicable to the BDG system.

2.1.10.2 Technical Evaluation

2.1.10.2.1 Introduction

The BDG system is described in FSAR Section 10.4.8. The BDG system design functions are

- The BDG system is used in conjunction with the condensate demineralizer, chemical addition, and sample systems to control the chemical composition of the steam generator shell side water chemistry to specified limits.
- The BDG system allows for the diversion of blowdown liquid to the radioactive liquid waste system in the event of a high-radiation signal resulting from a steam generator tube leak.
- The BDG system isolation valves automatically close to support containment isolation in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment.

Continuous blowdown of the steam generators is used to reduce the quantities of solids that accumulate as a result of the boiling process. The BDG system provides protection against inleakage of impurities from the main condenser. The BDG system is designed such that blowdown can be accomplished by equal flow from each of the four SG's or with an equivalent total flow through a single steam generator. The current normal blowdown flow rate is 40 gpm for each steam generator and for blowdown through only one steam generator 160 gpm.

2.1.10.2.2 Description of Analyses and Evaluations

The BDG system and components were evaluated to ensure capability of performing intended functions at SPU conditions. The evaluations, which are based on an analyzed NSSS thermal power of 3666 MWt, addressed the following:

- Blowdown flow rates.
- Operating and design pressures and temperatures.
- Fluid velocities and the potential for increased flow accelerated corrosion at SPU conditions. The Flow Accelerated Corrosion Program is evaluated in Section 2.1.8, Flow-Accelerated Corrosion.
- Safety-related valve closure and testing requirements (containment isolation) are addressed in Section 2.2.4, Safety-Related Valves and Pumps.
- The review of piping/component supports is described in Section 2.2.2.2, Balance of Plant Piping and Supports (Non-Class 1).
- Protection against dynamic effects including missiles, pipe whip, and discharging fluids are addressed in Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and Section 2.5.1.3, Pipe Failures.
- Environmental qualification of the containment isolation valves is addressed in Section 2.3.1, Environmental Qualification of Electrical Equipment.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the proposed SPU on the conclusions reached in the MPS3 license renewal safety evaluation report for the BDG system. As stated in Section 2.1.10.1, the BDG system is within the scope of license renewal. There are no system/component modifications necessary to implement the proposed SPU. SPU activities will not add any new components nor introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no new or previously unevaluated materials in the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.1.10.2.3 Results

The DNC review covered effects of the proposed SPU on the ability of the BDG system to control steam generator chemistry. DNC will follow Westinghouse's recommendation that the secondary side water chemistry continue to be maintained within industry guidelines to provide an environment consistent with maintenance of controlled corrosion/erosion rates in secondary system carbon steel components.

The BDG system flow rates to control steam generator chemistry are based on SPU main steam flow rates and present chloride content limitations. The normal blowdown flow rate from each steam generator and the flow rate from one steam generator increase approximately 7.5 percent, which is essentially the same percentage increase as the SPU, to approximately 43 gpm and 172 gpm respectively. The BDG system was conservatively evaluated at 45 gpm and 180 gpm. Steam generator blowdown system piping and valves have been evaluated for this increase in blowdown rate and are acceptable for implementation of the proposed SPU.

The flow control valves were evaluated using the blowdown flow rates of 45 gpm from each of the four steam generators and 180 gpm from one steam generator along with the minimum steam generator pressure. The evaluation verified that the blowdown system is capable of accommodating the SPU blowdown flow rates. The flow control valves will need to be repositioned to control the blowdown flow as necessary. The evaluation concludes that the flow control valves will be 30 percent open at the lower flow rate and approximately 70 percent open when blowing down one steam generation. Analysis shows that the higher flow rate from one steam generator can be met when discharging to the condenser or to the circulating water tunnel. The flow control valves and level control valves have adequate margin for controllability.

Flow velocity increases due to 7.5 percent higher flow rates remain within industry design guidelines provided by Crane Technical Paper No. 410. See Table 2.1.10-1 for steam generator blowdown system piping flow rates and velocities at current, SPU, and design conditions. In addition, the system will continue to be monitored as part of the FAC Program as presented in Section 2.1.8.

The predicted SPU operating temperatures and pressures in the steam generators, steam generator blowdown tank and interconnecting piping and valves decrease slightly relative to current conditions. Therefore, the design conditions for the steam generator blowdown piping and components connected to the steam generators, which are based on the steam generator design parameters, remain bounded for SPU conditions.

The BDG lines penetrating containment are provided with air-operated isolation valves that are designed to close for containment isolation post-accident. The maximum SPU blowdown flow rates and pressures experienced by these valves at SPU do not exceed the existing valve design capabilities and, therefore, these valves continue to meet the containment isolation design function.

2.1.10.3 Conclusion

DNC has evaluated the effects of the proposed SPU on the BDG system. DNC concludes that the evaluation has adequately accounted for changes in system flow conditions and impurity levels and their effects on the BDG system. Based on this, DNC concludes that the BDG system will continue to be acceptable and will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-14 following the proposed SPU implementation. Therefore, DNC finds the proposed SPU acceptable with respect to the steam generator blowdown system.

Table 2.1.10-1 Steam Generator Blowdown System Velocities

BDG Section	Current Flow Rate, gpm	SPU Flow Rate, gpm	Design Flow Rate, gpm	Current Velocity ft/sec	SPU Velocity ft/sec	Design Velocity ft/sec	Industry Design Velocity, ft/sec
SGs to Header	40	45	99	1.4	1.6	3.4	4–10
Header to BDG Tank	160	180	394	1.1	1.3	2.8	4–10
Drain Lines	160	180	394	4.0	4.5	10	4–10

2.1.11 Chemical and Volume Control System

2.1.11.1 Regulatory Evaluation

DNC reviewed the current and life extension based programs for the CVCS and the BRS. The CVCS is referred to as the CHS in the FSAR. The CVCS consists of the charging, letdown, and seal water system; the chemical control, purification, and makeup system; and the boron thermal regeneration system. These systems (primarily the CVCS) provide the means for

- Maintaining water inventory and quality in the RCS.
- Supplying seal-water flow to the reactor coolant pumps and pressurizer auxiliary spray.
- Controlling the boron neutron absorber concentration in the reactor coolant.
- Controlling the primary water chemistry and reducing coolant radioactivity level.
- Supplying recycled coolant for demineralized water makeup for normal operation and high-pressure injection flow to the ECCS in the event of postulated accidents.

The acceptance criteria are based on:

- GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture.
- GDC-29, insofar as it requires that the reactivity control systems be designed to ensure an extremely high probability of accomplishing their safety functions in anticipation of operational occurrences.

Specific review criteria are contained in the SRP, Section 9.3.4, and the guidance provided in Matrix 1 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800), Section 9.3.4, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 safety-related structures, systems, and components with respect to nuclear design relative to conformance to

- GDC-14, Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.14.

  The RCS boundary is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits (FSAR Sections 3.7 and 3.9). RCS pressure boundary materials, selection, and fabrication techniques ensure a low probability of gross rupture or abnormal leakage.

In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions, such as seismic and pipe rupture, as discussed in FSAR Sections 3.6 and 3.7. The system is protected from overpressure by means of pressure-relieving devices as required by applicable codes (FSAR Section 5.2.2).

The RCS boundary has provisions for inspection, testing, and surveillance of critical areas to assess their structural and leak-tight integrity (FSAR Section 5.2.).

- GDC-29, Protection Against Anticipated Operational Occurrences, is described in FSAR Section 3.1.2.29.

  The MPS3 protection and reactivity control systems are designed to assure an extremely high probability of performing their required safety functions in any anticipated operational occurrences. FSAR Chapter 7 provides details of system design.

Only the charging, letdown, and seal water system is systematically analyzed for pipe rupture, since it qualifies as a high-energy pipe system (FSAR Section 3.6). The remaining CVCS subsystems are classified as moderate energy pipe systems.

As described in FSAR Section 9.3.4.2.2, the CVCS supports RCPB material integrity by maintaining the RCS water chemistry necessary to meet PWR RCS chemistry technical specifications.

As described in FSAR Section 9.3.4.1.1, the CVCS supports reactivity control, in addition to the reactivity control achieved by the control rods. Reactivity is controlled by regulating the concentration of boric acid solution, which acts as a neutron absorber, in the RCS.

As described in FSAR Section 6.2.4 and Table 6.3-3, the CVCS supports containment isolation system functions of limiting the release of potentially radioactive materials to the environment through CVCS piping sections which penetrate the containment.

In addition to the evaluations described in the FSAR, the MPS3's CVCS components were evaluated for plant license renewal. System and system component materials of construction, operating history, and programs used to manage aging effects are documented in NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3*,* dated August 1, 2005.

The CVCS components evaluated herein for the proposed SPU are discussed in the License Renewal SER in Sections 3.0, Applicant’s Use of the Generic Aging Lessons Learned Report and 3.2B, Unit 3 Aging Management of Engineered Safety Features Systems.
Section 2.3B.3.15.3 of NUREG-1838 concludes that there is reasonable assurance that MPS3 has adequately identified the CVCS components that are in the scope of license renewal, and subject to aging management review.

2.1.11.2 Technical Evaluation

2.1.11.2.1 Introduction

The CVCS is described in the FSAR Section 9.3.4. The CVCS provides safety-related and non-safety-related services in support of MPS3. The CVCS is designed to provide the following services to the RCS:

- Maintenance of programmed water level in the pressurizer, i.e., maintain required water inventory in the RCS.
- Maintenance of seal water injection flow to the reactor coolant pumps.
- Control of reactor coolant water chemistry conditions, activity level, soluble chemical neutron absorber concentration and makeup.
- Emergency core cooling (part of the system is shared with the emergency core cooling system).
- Provide means for filling and draining of the RCS.
- Boration and inventory control for safety-grade cold shutdown.
- Provide reactor coolant purification capabilities during a cold or refueling shutdown.

To perform the functions identified above, continuous feed and bleed is maintained between the RCS and the CVCS. Borated water is let down from the RCS, through a regenerative HX, to minimize thermal loss from the RCS. The pressure is reduced through orifices, and further cooling occurs in the letdown HX followed by a second pressure reduction. Borated water is returned to the RCS by the charging system, which also provides seal injection flow to the reactor coolant pumps.

The RCS chemistry may be altered by passing the letdown flow through demineralizers that remove ionic impurities. A filter removes suspended solids, and the gases dissolved in the coolant can be removed in the gas stripper while hydrogen gas is continually added to the coolant in the volume control tank (VCT). The boric acid concentration in the coolant is changed by the reactor makeup portion of the CVCS as required for reactivity control. Excess coolant may be diverted into the boron recovery portion of the CVCS for reprocessing into pure water and concentrated boric acid.

The CVCS also provides a means for adding chemicals to the RCS which control the pH of the coolant during initial startup and subsequent operation, scavenge oxygen from the coolant during startup, and counteract the production of oxygen in the reactor coolant due to radiolysis of water in the core region. The CVCS has the ability to maintain the RCS water chemistry within the limits specified in FSAR Table 5.2-4.

The function of soluble neutron absorber (boron) concentration control and makeup is provided by the Reactor Makeup Control System using 4 weight percent boric acid solution and reactor makeup water from the reactor makeup water storage tank. In addition, for emergency boration and makeup, the capability exists to provide refueling water or 4 weight percent boric acid to the suction of the centrifugal charging pumps.

The centrifugal charging pumps in the CVCS also serve as the high-head safety injection pumps in the emergency core cooling system. Other than the centrifugal charging pumps and associated piping and valves, the CVCS is not required to function during a loss-of-coolant accident (LOCA), except when the reestablishment of charging/letdown flow is required according to the emergency operation instructions. During a LOCA, the CVCS is isolated except for the centrifugal charging pumps and the piping in the safety injection path.

The boron recovery system (BRS) is capable of processing reactor coolant to recover primary grade water and boric acid for reuse or disposal. The liquid entering the BRS is produced by the feed and bleed operations necessary to maintain the boron concentration in the reactor coolant at the desired level. This liquid is reactor coolant letdown from the CVCS through the radioactive gaseous waste system (GWS). The liquid can be processed through a mixed bed demineralizer or through the degasifier.

The Westinghouse reload safety evaluation (RSE) process is designed to evaluate the primary system recovery holdup capacity for routine plant changes, such as core reloads, and infrequent plant changes, such as a plant uprating that results in a change to core operating conditions and initial core reactivity. Therefore, boron recovery holdup capability will be addressed during the RSE process for each reload cycle.

Section 9.3.4.2.4 of The MNPS-3, FSAR states that the BTRS is installed in the plant but not used. Therefore, the BTRS is excluded from the evaluations.

2.1.11.2.2 Description of Analysis and Evaluations

The CVCS was evaluated to ensure the system is capable of performing its intended functions for the range of nuclear steam supply system (NSSS) design parameters approved for the SPU (Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1). The evaluation was conservatively performed for an analyzed NSSS thermal power of 3666 Mwt.

The changes in NSSS design parameters that could potentially affect the CVCS design bases functions include the increase in core power and the allowable range of RCS full-load design temperatures. The increase in core power and the allowable range of RCS full-load design temperature may also affect the CVCS design bases requirements related to the core reload boron requirements. Additionally, the allowable range of RCS full-load design temperatures may affect the heat loads that the CVCS HXs must transfer to the component cooling water system (CCWS) and, in the case of the regenerative HX, to the charging flow.

The RCS fluid interfaces with the CVCS are the regenerative, letdown, seal water, and excess letdown heat exchangers. Design and operating conditions of the heat exchangers (HX) are reviewed to assure that the SPU conditions are bounded by the HX design and operating conditions.

Regenerative Heat Exchanger

The regenerative HX cools the normal letdown flow from the RCS, which is at RCS T_{cold} temperature. The design inlet (RCS T_{cold}) temperature of the regenerative HX is 560°F, which bounds the highest RCS T_{cold} temperature of 556.4°F for SPU conditions (Section 1.1, Table 1-1). Charging flow and temperature remain the same at uprating conditions. Since the inlet (letdown) temperature at SPU conditions (556.4°F) is lower than the design inlet temperature from the HX spec sheets, the outlet temperature (charging) is not adversely impacted by the SPU. This results in a lower inlet temperature to the letdown HX that is less than the design process inlet temperature of 290°F. The letdown (shell side) design temperature is 650°F, which bounds SPU conditions from a mechanical design standpoint. Therefore the performance of the regenerative HX remains essentially unchanged due to SPU and is acceptable at the SPU conditions, with no plant changes required.

Letdown Heat Exchanger

The letdown HX cools the letdown flow from the regenerative HX. Since the performance of the regenerative HX is essentially unchanged at SPU conditions, as discussed in the previous section, there is essentially no effect on the performance of the letdown HX. The normal inlet temperature will remain at 290°F. Minor differences in letdown temperature can easily be accommodated within the capability of the letdown HX cooling water temperature control valve, 3CCP*TV172. The letdown (tube side) design temperature of 400°F exceeds the original operating inlet temperature of 380°F, which also bounds the SPU condition from a mechanical design standpoint. Therefore, it is concluded that acceptable letdown HX performance is provided at the SPU conditions, with no plant changes required.

Excess Letdown Heat Exchanger

The excess letdown HX cools the excess letdown flow from the RCS via the RCS cold leg or the reactor vessel head vent system. An inlet (RCS T_{cold}) temperature of 560°F was analyzed for the excess letdown HX, which bounds the highest RCS T_{cold} temperature associated with the RCS T_{avg} window for SPU. In addition, the letdown (tube side) design temperature of 650°F bounds the SPU condition of 556.4°F for RCS T_{cold} and 628°F for RCS T_{core} from a mechanical design standpoint. The performance of the excess letdown HX is acceptable at SPU conditions, with no plant changes required.

Seal Water Heat Exchanger

The seal water HX cools the seal return flow from the RCP seal water return to the volume control tank, reactor coolant discharged from the excess letdown HX (if in service), and the miniflow from a centrifugal charging pump. The RCP heat load (including thermal barrier HX) is a function of RCS T_{cold} temperature, while the excess letdown heat load is a function of excess letdown HX performance, and the miniflow heat load is a function of the letdown HX performance. Since the SPU RCS T_{cold} temperature remains below design conditions of the letdown HX and excess letdown HX, the performance of the seal water HX is acceptable at SPU, with no plant changes required.

Charging, Letdown, and RCS Makeup (Boration, Dilution, Purification, and N-16 Delay Time)

As discussed in the previous sections for the various CVCS HXs, there are essentially no effects on their performance at the SPU conditions. The charging and letdown flows are not impacted by the SPU since the RCS pressure and the CVCS orifice alignment remain unchanged.

The flow capacity performance of the RCS makeup system is independent of the change in RCS conditions resulting from the SPU conditions. However, the makeup system also relies on storage capacity of various sources of water, including primary makeup water and boric acid solutions from both the boric acid storage tanks and the refueling water storage tank (RWST).

Primary makeup water is used to dilute RCS boron, to provide positive reactivity control, or to blend concentrated boric acid to match the prevailing RCS boron concentration during RCS inventory makeup operations. Since the flow capacity performance of the RCS makeup system is independent of the change in RCS conditions resulting from the SPU conditions as discussed above, the SPU does not affect the capability of the makeup water system to perform these system functions.

The boric acid storage tanks (BAST) and RWST provide the sources of boric acid for providing negative reactivity control to supplement the reactor control rods. The SPU is expected to have a small effect on the boration requirements that must be provided by the CVCS boration capabilities. The maximum expected RCS boron concentrations are within the capability of the CVCS. The Westinghouse reload safety evaluation (RSE) process (currently incorporated into Millstone Technical Specifications) is designed to address boration capability for routine plant changes, such as core reloads, and infrequent plant changes, such as a plant uprating that result in a change to core operating conditions and initial core reactivity. Therefore, boration capability will be addressed during the RSE process for each reload cycle.

The CVCS letdown flow is fixed and charging flow is varied to control pressurizer water level and RCS inventory. The pressurizer water level is programmed as a function of temperature to accommodate RCS coolant expansion. Accordingly, this programmed level is being changed based on the SPU NSSS design parameters. However, this change has no impact on the ability of the CVCS to maintain RCS inventory, which is accomplished via letdown, charging, and makeup.

The letdown flow path is routed inside Containment such that there is adequate decay of N-16 before the letdown fluid leaves the Containment building. It is noted that the letdown line and excess letdown line radiation dose rates from N-16 (for example, amount of N-16) will increase proportional to the increase in reactor power level. Since the letdown flow rate is essentially unchanged, as discussed in the previous paragraphs, this radiation protection feature of the CVCS is not impacted by the SPU.

High-head safety injection flow provided by the centrifugal charging pumps is determined by hydraulic resistances, post-accident RCS backpressure, and centrifugal charging pumps performance, which are not directly affected by the SPU.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the CVCS at SPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. A review of internal and industry operating experience has not identified the need to modify the basis for aging management programs to account for the effects of SPU. Thus, no new aging effects requiring management are identified.

2.1.11.2.3 Results

The evaluations of the CVCS charging, letdown, and RCS makeup performance show the CVCS is acceptable at the SPU conditions, with no plant changes. Accordingly, the performance of the following CVCS functions (which are accomplished via charging, letdown, and makeup) are acceptable at SPU conditions, with no plant changes:

- Maintenance of programmed water level in the pressurizer, i.e., maintain required water inventory in the RCS.
- Maintenance of seal-water injection flow to the reactor coolant pumps.
- Control of reactor coolant water chemistry conditions, activity level, soluble chemical neutron absorber concentration and makeup.
- Emergency core cooling (part of the system is shared with the emergency core cooling system).
- Provide means for filling and draining of the RCS.
- Boration and inventory control for safety-grade cold shutdown.
- Provide reactor coolant purification capabilities during a cold or refueling shutdown

The CVCS boration capability is addressed during the reload safety evaluation (RSE) process (currently incorporated into Millstone Technical Specifications) for each core re-load cycle (Reference 1).

The performance of the CVCS components, including valves and piping that support Containment isolation, are not affected by change in RCS design parameters resulting from SPU. The requirement for Containment isolation as described in the Westinghouse System Standard Design Criteria for NSSS for Containment isolation is not impacted (Reference 2).

There is a small increase in letdown line dose rates from N-16, proportional to the increase in reactor power level. This small increase has been evaluated in Section 2.10.1, Occupational and Public Radiation Doses, as being acceptable.

Refer to Section 2.2.2.1, NSSS Piping, Components and Supports, for results of the evaluation of the CVCS Class 1 piping, including RCS nozzles and thermal sleeves.

The CVCS support functions provided by the waste disposal system are not affected by the change in RCS conditions resulting from the SPU. See Section 2.5.6.1.

2.1.11.3 Conclusion

DNC has reviewed the evaluation of the effects of the SPU on the CVCS and boron recovery system and concludes that the evaluation adequately addressed changes in the temperature of the reactor coolant and their effects on the CVCS and boron recovery system. DNC further concludes that the CVCS and boron recovery system continue to be acceptable and continue to meet the requirements of GDC-14 and GDC-29 following implementation of the SPU. Therefore, DNC finds the SPU acceptable with respect to the CVCS.

2.1.11.4 References

1. WCAP-9272-P-A, Westinghouse Reload Safety Evaluation Methodology, F. M. Bordelon et al., July 1985

2. Westinghouse System Standard Design Criteria SSDC 1.14, Nuclear Steam Supply System “containment isolation,” Rev. 3, September 1981.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

2.2.1.1 Regulatory Evaluation

SSCs important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. DNC conducted a review of pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures. The DNC review covered (1) the implementation of criteria for defining pipe break and crack locations and configurations, (2) the implementation of criteria dealing with special features, such as augmented in-service inspection programs or the use of special protective devises such as pipe-whip restraints, (3) pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects, and (4) the design adequacy of supports for structures, systems, and components provided to ensure that the intended design functions of the SSCs, will not be impaired to an unacceptable level as a result of pipe-whip or jet impingement loadings. The DNC review focused on the effects that the proposed SPU may Shave on items (1) through (4) above.

The acceptance criteria for this review is:

- GDC-4, insofar as it requires SSCs important to safety to be designed to accommodate the dynamic effects of a postulated pipe rupture.

Specific review criteria are contained in the SRP Section 3.6.2 and guidance is provided in Matrix 2 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 3.6.2, Rev. 1. MPS3 took the following exceptions to SRP 3.6.2 (Rev. 1) as presented in FSAR Section 1.9.

- Section III.2.a- Uses internal pressure, and temperature conditions in the piping system during reactor operation at 100 percent power instead of pressure and temperature values corresponding to the greater contained energy at hot standby or at 102 percent power.
- Section III.2.a-Uses an allowable of 80 percent of energy absorbing capacity based on static testing instead of limiting the allowable capacity for crushable material to 80 percent of its rated energy absorbing capacity as determined by dynamic testing.
- BTP MEB 3-1, B.1.e- MPS3 does not postulate cracks in high energy piping.

As noted in the FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978.

The adequacy of the MPS3 design relative to the GDC is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design regarding conformance to:

- GDC-4 is described in the FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4)

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCA's. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

  In a letter from B. J. Youngblood (NRC) to J. F. Opeka (NNCO) dated June 5, 1985, Millstone 3 was granted an exemption for a period of two cycles of operation from those portions of General Design Criterion 4 which require protection of structures, systems, and components from the dynamic effects associated with postulated breaks in the reactor coolant system primary loop piping.

  In Federal Register, Volume 51, No. 70, dated April 11, 1986, the NRC published a final rule modifying General Design Criterion 4 to allow the use of leak-before-break technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in pressurized water reactors. This rule obviates the need for the above exemption.

  Structures, systems, and components important to safety are classified as QA Category 1 and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

  FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

FSAR Section 3.6 describes the design features that protect essential equipment from the consequences of postulated piping failures both inside and outside containment. FSAR Section 3.6 also presents the results of analyses initiated in response to NRC RG 1.46 for inside containment and the AEC letter from A. Giambusso, dated December 18, 1972, for outside containment. The methods of evaluation, however, reflect the approach and methodology contained in the Branch Technical Positions ASB 3-1 and MEB 3-1 as qualified in FSAR Sections 3.6.1 and 3.6.2. The analyses resulted in the implementation of various features, such as provision of pipe whip restraints, jet impingement shields, enclosures, and physical separation of essential systems to satisfy the requirements of GDC-4.

High energy pipe breaks and moderate energy pipe cracks were postulated as required per BTP MEB 3-1 of Standard Review Plan Section 3.6.2 of NUREG 0800. Pipe whip restraints, jet impingement shields, enclosures or physical separation of essential systems have been implemented to mitigate the effects of the postulated pipe breaks/pipe cracks.

Postulated Piping Failures in Fluid Systems Inside Containment

High energy piping lines inside containment were evaluated for the effects of potential pipe breaks. Design basis pipe break criteria are presented in FSAR Section 3.6.2.1. The criteria for protection against pipe breaks inside containment are presented in NRC RG 1.46 as discussed in FSAR Section 3.6.1.1.1 with exceptions specified in FSAR Section 1.8. FSAR Section 3.6.1.1.4 discusses design features provided to protect essential systems, components, and structures and to mitigate the consequence of piping failures.

Postulated Piping Failures in Fluid Systems Outside Containment

The AEC letter from A. Giambrusso dated December 18, 1972, requested an analysis of the effects of postulated failures of high energy lines outside containment. Design basis break and crack locations, type and orientation are postulated in accordance with the information presented in FSAR Section 3.6.1.1.2.

Other FSAR sections discussing the design of BOP and Non-class 1 piping and supports that are potentially impacted by pipe rupture and their dynamic effects include:

FSAR Section 3.2, Classification of Structure, Components, and Systems, provides details with respect to the seismic classification of piping and piping components.

FSAR Section 3.7, Seismic Design, and specifically Section 3.7.3.1, Seismic Analysis methods, provides details with respect to the seismic qualification of piping and piping components.

FSAR Section 3.9, Mechanical System and Components, specifically Section 3.9B.2.1, Preoperational Vibration and Dynamic Effects Testing on Piping.

The MPS3 pipe rupture locations and associated dynamic effects were evaluated for their continued acceptability to support plant license renewal. NUREG 1838, Safety Evaluation Report related to the License Renewal of Millstone Power Station, Unit 2 and 3, dated August 1, 2005 documents the results of that review. NUREG-1838 Section 4.7.B.3 is applicable to pipe rupture locations in primary loop piping and associated dynamic effects.

2.2.1.2 Technical Evaluation

2.2.1.2.1 Introduction

SSCs could be impacted by the pipe-whip dynamic effects of a pipe rupture. DNC conducted a review of pipe rupture analyses to ensure that those SSCs are adequately protected from the effects of pipe ruptures.

Refer to Section 2.5.1.3, Pipe Failures, for discussion of plant design for protection from piping failures outside containment.

2.2.1.2.2 Description of Analyses and Evaluations

The current structural design basis of MPS3 includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. LBB is addressed in Section 2.1.6; which describes the evaluations performed to demonstrate that the elimination of these breaks from the structural design basis continues to be valid following implementation of the SPU, and that primary loop piping for which the licensee credits LBB continue to comply with the requirements of GDC-4, the draft SRP, Section 3.6.3 and NUREG-1061 Volume 3. The evaluations performed in support of Section 2.1.6 are credited in this LR with respect to excluding the dynamic affects of postulated ruptures in primary coolant loop piping.

Affected piping systems as described in FSAR Sections 3.6.1 and 3.6.2 were evaluated to address revised SPU operating conditions. Applicable pipe rupture/environmental crack postulation criteria were reviewed as well as changes to piping operating temperatures and pressures, and piping system stress levels resulting from SPU were reviewed against pipe break evaluation requirements. Pipe stresses for break exclusion zones were demonstrated to be within acceptable limits. The SPU evaluations performed for applicable piping systems did not result in any new or revised break/crack locations, and the design basis for pipe break, jet impingement, pipe whip and environmental considerations remain valid for SPU.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 License Renewal Safety Evaluation Report for pipe break, jet impingement and pipe whip considerations. As stated in Section 2.2.1.1 pipe rupture locations and dynamic effects are within the scope of license renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with the evaluation of pipe break, jet impingement, and pipe whip considerations at SPU conditions and the SPU does not add any new pipe breaks or previously unevaluated pipe breaks to the system. There are no modifications to existing plant pipe rupture related support components. Thus, no new aging effects requiring management are identified.

2.2.1.2.3 Results

The proposed SPU does not result in any new or revised break locations, and based on the evaluations performed for SPU noted above, the following were demonstrated.

- Existing criterion for defining pipe break and crack locations and configurations is unaffected by SPU.
- Criterion dealing with special features, such as augmented ISI programs or the use of special protective devices such as pipe whip restraints is unaffected by SPU.
- Existing pipe whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe whip dynamic effects remain valid for SPU.

- Existing design of SSCs remain acceptable to protect safety related SSCs from the effects of pipe whip and jet impingement loading for SPU.

Hence, for rupture and crack postulation issues, the MPS3 piping and support systems continue to meet their licensing basis and satisfy the requirements of GDC-4.

2.2.1.3 Conclusion

DNC has reviewed the evaluations related to determinations of rupture locations and associated dynamic and environmental effects and concludes that the evaluations have adequately addressed the effects of the proposed SPU on them. DNC further concludes that the evaluations have demonstrated that SSCs important to safety will continue to meet the MPS3 current licensing basis requirements with respect to GDC-4 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the determination of rupture locations and dynamic effects associated with the postulated rupture of piping.

2.2.2 Pressure-Retaining Components and Component Supports

Introduction

In keeping with the format of RS-001 Rev. 0, this LR section is arranged differently than other LR sections. The following Regulatory Evaluation subsection generally applies to all the specific components addressed individually in later Technical Evaluation subsections. In addition to the generic Regulatory Evaluation, any amplifications or qualifications necessary for individual component types are provided in the Introduction section for each component.

This document contains a CLB subsection that addresses MPS3 compliance with the generic Regulatory Evaluation criteria. In addition to the generic CLB subsection, when necessary, a component-specific CLB provides further details pertinent to that component, and explains any exception to the generic CLB.

Regulatory Evaluation

DNC has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the ASME B&PV Code, Section III, Division 1 and GDC-1, -2, -4, -14 and -15. The DNC review focused on the effects of the proposed SPU on the design input parameters and the design-basis loads and load combinations for normal, upset, emergency and faulted conditions. The DNC review covered the analyses of flow-induced vibration and the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The DNC review also included a comparison of the resulting stresses and CUFs against code-allowable limits.

The acceptance criteria are based on:

- 10 CFR 50 Part 55a and GDC-1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed
- GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions
- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents
- GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture
- GDC-15, insofar as it requires that the RCS be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation

Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1 and other guidance provided in Matrix 2 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800) and SRP Sections 3.9.1 (Rev. 2), 3.9.2 (Rev. 2), 3.9.3 (Rev. 1) and 5.2.1.1 (Rev. 1). As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the GDC is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the MPS3 pressure retaining components and component supports' design adequacy regarding conformance to:

- 10 CFR 50.55a is described in FSAR Section 5.2.1.1, Compliance with 10 CFR 50.55a.

  RCS components are designed and fabricated in accordance with 10 CFR 50.55a. The actual addenda of the ASME B&PV Code applied to the original design of each component are listed in FSAR Table 5.2-1.

- GDC-1 is described in the FSAR Section 3.1.2.1, General Design Criterion1 - Quality Standards and Records.

  SSCs important to safety are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Quality standards applicable to safety related SSCs are generally contained in codes such as the ASME B&PV Code. The applicability of these codes is specifically identified throughout the MSP3 FSAR and is summarized in FSAR Section 3.2.5.

  FSAR Chapter 17 provides direct reference to the Quality Assurance Program established to provide assurance that safety related SSCs satisfactorily perform their intended safety functions. The procedures for generating and maintaining appropriate design, fabrication, erection, and testing records are contained within the referenced documents.

- GDC-2 is described in the FSAR Section 3.1.2.2, General Design Criterion 2 - Design Bases for Protection Against Natural Phenomena.

  Those features of plant facilities that are essential to the prevention of accidents that could affect the public health and safety or to the mitigation of accident consequences are designed to:

  1. Quality standards that reflect the importance of the function to be performed. Approved design codes are used when appropriate to the nuclear application.

  2. Performance standards that enable the facility to withstand, without loss of the capability to protect the public, the additional forces imposed by the most severe earthquake, flooding condition, wind, ice, or other natural phenomena for the site, and credible combinations of the effects of normal and accident conditions with the effects of the natural phenomena.

  Features of the facility essential to accident prevention and mitigation of accident consequences, which are designed to withstand the effects of natural phenomena are:

1. The reactor coolant pressure boundary and containment barriers

2. The controls and emergency cooling systems whose functions are to maintain the integrity of these barriers

Reactor and safety related system piping, components, and supporting structures are designed to withstand a specified seismic disturbance and credible combinations of effects of normal and accident conditions coincident with the effects of natural phenomena. Plant design criteria specify that there is to be no loss of function of such equipment in the event of the SSE ground acceleration acting in the horizontal and vertical directions simultaneously.

- GDC-4 is described in the FSAR Section 3.1.2.4, General Design Criterion 4 - Environmental and Missile Design Bases.

  SSCs important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

  SSCs important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in the FSAR Section 3.2.5.

  FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the SSC important to safety are designed.

- GDC-14 is described in FSAR Section 3.1.2.14, General Design Criterion 14 – Reactor Coolant Pressure Boundary.

  The RCS boundary is designed to accommodate the system pressures and temperatures attained under all modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits (FSAR Section 3.9). RCPB materials, selection, and fabrication techniques ensure a low probability of gross rupture or abnormal leakage.

  In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions, such as seismic and pipe rupture, as discussed in FSAR Sections 3.6 and 3.7. The system is protected from overpressure by means of pressure relieving devices as required by applicable codes (FSAR Section 5.2.2).

  The RCS boundary has provisions for inspection, testing, and surveillance of critical areas to assess the structural and leak tight integrity (FSAR Section 5.2.2). For the reactor vessel (FSAR Section 5.3), a material surveillance program conforming to applicable codes is provided.

- GDC-15 is described in FSAR Section 3.1.2.15, General Design Criterion 15 – Reactor Coolant System Design.

  The design pressure and temperature for each component in the reactor coolant and associated auxiliary, control and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

  Additionally, RCPB components achieve a large margin for safety by the use of proven ASME materials and design codes, use of proven fabrication techniques, nondestructive shop testing, and integrated hydrostatic testing of assembled components. FSAR Chapter 5 discusses RCS design.

FSAR Section 3.9B.2 describes the dynamic testing and analysis conducted on BOP components, while Section 3.9N.2 describes the dynamic testing and analysis conducted on NSSS components.

The MPS3 pressure-retaining components and supports were evaluated for continued acceptability regarding plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, documents the results of that review. The individual NUREG-1838 sections which apply to both components and component supports are discussed in Sections 2.2.2.1 through 2.2.2.7. NUREG-1838, Appendix A, “Commitments for License Renewal of MPS Unit 3”, are discussed in Sections 2.2.2.1 through 2.2.2.7 as they apply to specific RCS components.

2.2.2.1 NSSS Piping, Components and Supports

2.2.2.1.1 Introduction

This LR section addresses NSSS Piping, Components, and Supports. BOP Piping and Supports (Non-class 1) are presented in Section 2.2.2.2. The NSSS piping, which is the RCS piping, consists of four heat transfer piping loops (loops A, B, C and D) connected in parallel to the RPV. FSAR Figure 3.6-12 presents the RCS piping arrangement. Each loop contains a RCP and a steam generator. Each RCS loop consists of three legs: the hot leg from the RPV to the steam generator, the cross-over leg from the steam generator to the RCP, and the cold leg from the RCP to the RPV. The system also includes a pressurizer, pressurizer relief tank, connecting piping including pressurizer spray piping, and the instrumentation for operational control.

The pressurizer is connected to loop B (loop 2). Auxiliary system piping connections into the RCS piping are provided as necessary. The RCS piping is supported by the primary equipment supports of the RCS, namely the RPV supports, the steam generator supports, the RCP supports, and the pressurizer supports.

MPS3 Current Licensing Basis

The generic CLB in Section 2.2.2 applies to NSSS Piping, Components and Supports, with the following amplifications.

FSAR sections that discuss the design of NSSS piping and supports include:

- FSAR Section 3.2, Classification of Structure, Components, and Systems, provides details with respect to the seismic classification of piping and piping components.
- FSAR Sections 3.7N, Seismic Design, provides details with respect to the seismic design of SSCs that comprise the NSSS Scope qualification of piping and piping components.
- FSAR Section 3.9N, Mechanical System and Components, provide details with respect to the design of RCS components.
- FSAR Section 5.4, Component and Subsystem Design, provides details with respect to the design of NSSS structures, systems, and components.

In addition to the evaluations described above, the NSSS piping, components, and supports were evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005 documents the results of that review. NUREG-1838 Sections 2.3B.1.3, 3.1.B and 4.3B are applicable to the NSSS piping and supports.

2.2.2.1.2 Technical Evaluation

2.2.2.1.2.1 Introduction

The NSSS piping, components, and supports, including primary equipment supports for the steam generators, RC pumps, Pressurizer, and Reactor Vessel (support for the RV is the neutron shield tank) were evaluated to assess the impact of operational changes that will result due to implementation of SPU. The NSSS piping and supports systems were evaluated to the ASME

B&PV, Section III code Class 1, 1971 Edition and addenda through Summer 1973. The existing design basis analyses for RCL piping and associated branch piping, RCL primary equipment supports and pressurizer surge line were reviewed relative to the impact associated with the implementation of SPU.

Specifically, the following items were evaluated and, where necessary, reanalyzed with SPU parameters:

- RCL LOCA analysis using Loop LOCA hydraulic forces and the associated Loop LOCA RPV motions for the SPU program
- RCL piping stresses
- RCL displacements at branch piping connections to assess the impact on the branch piping analyses
- Pressurizer surge line piping analysis including the effects of thermal stratification
- RCL primary equipment support and nozzle loads (Reactor Vessel, Steam Generator, Reactor Coolant Pump, and Pressurizer)

2.2.2.1.2.2 Description of Analyses and Evaluations

The NSSS piping, component and support design parameters that will change due to the implementation of SPU were reviewed for impact upon the RCL piping and supports, including equipment nozzles and primary equipment supports, and consequent impact to the branch lines attached to the RCL.

The following provides a summary of specific design parameters that changed due to SPU and were reconciled as part of the NSSS piping and support evaluations.

Nuclear Steam Supply System Performance Capability Working Group Design Parameters

The design parameters for operation at 3666 MWt (NSSS) power, as identified in Tables 1-1 and 1-2 of Section 1.1, Nuclear Steam Supply System Parameters were considered in the evaluation of the RCL and associated branch line piping systems.

NSSS Design Transients

The impact on design transients due to the changes in full-power operating temperatures for the SPU program is addressed in Section 2.2.6, NSSS Design Transients. The RCL piping and associated branch piping was evaluated to address the specific changes in design transient data resulting from SPU.

Loop LOCA Hydraulic Forcing Functions Forces and Associated Loop LOCA RPV Motions

The impact of the SPU Program on the Loop LOCA hydraulic forcing functions is addressed in Section 2.8.5.6.3, and the associated loop LOCA RPV motions are addressed in Section 2.2.3, Reactor Pressure Vessel Internals and Core Supports. By virtue of LBB, breaks are not postulated for the RCL loop hot leg, cold leg and crossover leg piping (See Section 2.1.6, Leak-Before-Break).

For the SPU program, the loop LOCA hydraulic forcing function forces and associated loop LOCA RPV motions from applicable RCL branch line breaks were reconciled as part of the RCL and associated branch piping and support evaluations.

Steam Generator and Pressurizer Cubicle Pressurization Effects Due to Pipe Break

The effects of Steam Generator and Pressurizer cubicle pressurization due to pipe breaks related to SPU conditions were reconciled as part of the RCL and associated branch piping evaluations.

The computer program NUPIPE-SWPC was used in performing the SPU piping evaluations. This computer program is not currently described in the FSAR and was used to calculate stresses and loads using the appropriate equations from the ASME III Code. Using an approved Quality Assurance Program this program has been verified and validated and shown to be accurate and acceptable for use in NSSS piping applications.

The NUPIPE-SWPC program is designed to perform analyses in accordance with the ASME Boiler and Pressure Vessel Code, Section III Nuclear Power Plant Components and the ANSI/ASME B31.1 Power Piping Code.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in NUREG-1838 for the NSSS Piping, Components, and Supports and has determined that the evaluations remain valid for the SPU conditions. As stated in Section 2.2.2.1, NSSS Piping, Components and Supports are within the scope of License Renewal.

DNC has evaluated the impact of the SPU on the fatigue evaluations performed in support of license renewal and has determined that the fatigue analyses performed to support license renewal bounds and remains valid for SPU conditions.

2.2.2.1.2.3 Results

Table 2.2.2.1-1 provides a summary of current stress and/or CUF, revised stress and/or CUF levels for SPU conditions, and the resulting design margins for each piping analysis that required detailed evaluation to reconcile SPU conditions. Piping systems not specifically listed in Table 2.2.2.1-1 did not require detailed evaluation to reconcile SPU conditions. The results reported have incorporated the RCL LOCA hydraulic forcing functions and associated loop LOCA reactor pressure vessel motions, as applicable, that were reconciled as part of the SPU evaluations.

The NSSS piping stress and support evaluations performed, including evaluations of primary equipment supports for the steam generators, RC pumps, Pressurizer, and Reactor Vessel, conclude that NSSS piping systems remain acceptable and will continue to satisfy design basis requirements when considering the operational effects resulting from SPU conditions.

The results of the equipment nozzle evaluations concluded that these components remain within acceptable limits for SPU conditions.

2.2.2.1.3 Conclusion

DNC concludes that the evaluations have adequately accounted for the effects of the proposed SPU on NSSS piping, components and supports. Based on this, it is concluded that the pressure-retaining components and their supports will continue to meet the MPS3 current licensing basis with respect to the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14 and GDC-15. DNC finds the proposed SPU is acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

Table 2.2.2.1-1
Stress Summary at SPU Conditions

Piping Analysis Description	Loading Condition	Current Stress (psi) /CUF	SPU Stress (psi)/CUF	Allowable Stress (psi)/CUF	Design Ratio (Note 1 & 5)
Reactor Coolant Loops A and Loop C	Equation 9 (Faulted)	44,807	50,666	53,400	0.95
	CUF	0.9947	0.9964	1.0	0.9964
Reactor Coolant Loops B and Loop D	Equation 9 (Faulted)	45,038	51,825	53,400	0.97
	CUF	0.7162	0.8047	1.0	0.8047
2” Loop Fill to XL Loop A 3-RCS-002-128-1	Equation 9 (Faulted)	16,920	19,053	49,476	0.39
	CUF	0.0831	0.0832	1.0	0.0832
2” Loop Drain to XL Loop A 3-RCS-002-127-1	Equation 9 (Faulted)	25,035	27,197	49,800	0.55
	CUF	0.9653	0.9653	1.0	0.9653
2” Loop Drain to XL Loop C 3-RCS-002-135-1	Equation 9 (Faulted)	23,310	27,079	49,800	0.54
	CUF	0.988	0.988	1.0	0.988
2” Loop Fill to XL Loop C 3-RCS-002-136-1	Equation 9 (Faulted)	18,420	20,294	49,476	0.41
	CUF	0.0073	0.0074	1.0	0.0074
2” Loop Drain to XL Loop D 3-RCS-002-143-1	Equation 9 (Faulted)	23,757	25,198	49,800	0.51
	CUF	0.9834	0.9834	1.0	0.9834
2” Loop Fill to XL Loop B 3-RCS-002-131-1	Equation 9 (Faulted)	17,918	19,432	49,800	0.39
	CUF	0.07	0.07	1.0	0.07
2” Loop Drain to XL Loop B 3-RCS-002-130-1	Equation 9 (Faulted)	35,148	39,677	49,800	0.80
	CUF	0.89	0.89	1.0	0.89
10” SI (CL) Loop D 3-RCS-010-146-1	Equation 9 (Faulted)	21,369	21,369	25,050	0.85
	CUF	0.8913	0.8974	1.0	0.8974
6” SI (HL) Loop B 3-RCS-006-119-1	Equation 9 (Faulted)	27,502	27,502	50,100	0.55
	CUF	0.3464	0.5358	1.0	0.5358

Table 2.2.2.1-1
Stress Summary at SPU Conditions

Piping Analysis Description	Loading Condition	Current Stress (psi) /CUF	SPU Stress (psi)/CUF	Allowable Stress (psi)/CUF	Design Ratio (Note 1 & 5)
3" SI Loop A 3-RCS-003-121-1	Equation 9 (Faulted)	13,332	13,332	49,800	0.27
	CUF	0.6921	0.6928	1.0	0.6928
6" SI Loop C 3-RCS-006-120-1	Equation 9 (Faulted)	42,648	42,648	60,000	0.71
	CUF	0.1977	0.1987	1.0	0.1987
3" Letdown Loop C 3-RCS-003-137-1	Equation 9 (Faulted)	18,144	18,144	49,800	0.36
	CUF	0.6721	0.6723	1.0	0.6723
2" Loop Fill to XL Loop D 3-RCS-002-144-1	Equation 9 (faulted)	19,236	21,326	49,476	0.44
	CUF	0.0102	0.0104	1.0	0.0104

NOTES:
(1) Design Ratio reported is based on the ratio of SPU stress/allowable stress or SPU CUF/allowable CUF as applicable
(2)XL = Crossover Leg, RCS = Reactor Coolant System, CL = Cold Leg, HL = Hot Leg
(3) Equation 9 Faulted and CUF increases shown for SPU are due to revised loop hydraulics and the loss of power transient.
(4) CUF = Cumulative Usage Factor.
(5) All stress levels and CUFs resulting in design margins less than or equal to 1.0 are acceptable limits in accordance with the AMSE III code. The allowable stress levels for this code are stress levels that are well below material yield and/or ultimate stress limits.

2.2.2.2 Balance of Plant Piping and Supports (Non-Class 1)

2.2.2.2.1 Introduction

BOP piping and supports are reviewed as part of the SPU. This section covers Non-Class 1 piping and its supports that are not included in Section 2.2.2.1, NSSS Piping, Components and Supports. Section 2.2.2.1 covers Class 1 reactor coolant loop and safety injection piping and supports up to the Class 1 boundary.

MPS3 Current Licensing Basis

The generic CLB in Section 2.2.2 applies to BOP piping and supports, with the following amplifications.

FSAR sections that discuss the design of BOP piping and supports include:

- FSAR Section 3.2, Classification of Structure, Components, and Systems, provides details with respect to the seismic classification of piping and piping components.
- FSAR Section 3.7, Seismic Design, Seismic Analysis Methods, provides details with respect to the seismic qualification of piping and piping components.
- FSAR Section 3.9B, Mechanical System and Components, Dynamic Testing and Analysis – Piping systems, provide details with respect to the seismic qualification of BOP piping and piping components.

The BOP piping and supports were evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005 documents the results of that review. NUREG-1838 Sections 2.4B.4.1 and 3.5B.2.3.3.6 are applicable to the BOP piping and supports.

2.2.2.2.2 Technical Evaluation

2.2.2.2.2.1 Introduction

BOP piping and support systems were evaluated to assess the impact of operating temperature, pressure and flow rate changes that will result due to the implementation of SPU. The BOP piping and supports were evaluated to the ASME B&PV Code, Section III Code Class 2 and 3, 1971 Edition and addenda through Summer 1973 and ANSI B31.1 – 1973 Code for Pressure Piping through Summer 1973 Addenda, as described in FSAR Sections 3.7 and 3.9.

The BOP piping and support systems that were evaluated for SPU conditions included the following systems:

Main Steam

Feedwater

Condensate

Feedwater Heater Vents and Drains

Moisture Separator Vents and Drains

Extraction Steam

Circulating Water

Component Cooling Water

Auxiliary Feedwater

Spent Fuel Pool Cooling

Service Water

Steam Generator Blowdown

Radwaste Systems

Safety Injection (BOP)

Chemical and Volume Control

Residual Heat Removal

Quench Spray

Recirculation Spray

2.2.2.2.2.2 Description of Analyses and Evaluations

System operation at SPU conditions results in increased pipe stress levels and pipe support and equipment loads when those SSCs experience higher operating temperatures, pressures or flow rates.

Current and SPU operating data (operating temperature, pressure and flow rate) were obtained from heat balance diagrams and calculations. Thermal, pressure and flow rate “change factors” were determined, as required, to compare and evaluate changes in SPU operating conditions. The “change factors” were based on the following ratios:

- The thermal “change factor” equals the ratio of the SPU to actual analyzed operating temperature. That is, thermal change factor is $(T_{SPU}\text{-}70°F)/(T_{analyzed}\text{-}70°F)$.
- The pressure “change factor” was determined by the ratio of $(Pressure_{SPU}/Pressure_{analyzed})$.
- The flow rate “change factor” was determined by the ratio of $(Flow\ rate_{SPU}/Flow\ Rate_{analyzed})$

Based on the magnitude of the calculated change factors, the following engineering activities were performed and/or conclusions reached.

For change factors less than or equal to 1.00 (that is, the current condition envelopes or equals the SPU condition), the piping and support system was concluded to be acceptable for SPU conditions.

For change factors greater than 1.00, an additional evaluation was performed to address the specific increase in temperature, pressure and/or flow rate in order to determine piping and support system acceptability, as well as nozzle load and containment penetration acceptability.

The BOP piping and support systems listed in Section 2.2.2.2.2.1 (Introduction) have been evaluated relative to the impact of SPU.

Flow rate increases due to SPU occur mainly in systems related to the main power cycle (i.e, main steam, feedwater, condensate, extraction steam, feedwater heater vents and drains, MSR vents and drains). The two piping systems of most concern with respect to flow rate increases are main steam and feedwater systems. The SPU flow rates and its impact on potential flow induced fluid transient loads were evaluated for the main steam and feedwater piping systems. The assessment of the main steam system revealed that the existing flow rates considered in the current design basis fluid transient analyses (e.g., steam hammer loads associated with a TCV/TSV fast closure event) used conservative (i.e., bounding) values, that are higher than the main steam SPU flow rate. Hence, the main steam system is acceptable for SPU conditions and does not require any additional evaluations. However, an evaluation of the feedwater system was required to address the flow rate increase resulting from SPU and its impact on fluid transient loads (i.e., water hammer loads) resulting from feedwater isolation valve closure/feedwater pump trip events. The revised feedwater system fluid transient loads at SPU conditions for affected pipe supports were determined by revision to applicable pipe stress analyses. Using the revised fluid transient loads corresponding to SPU conditions, a revised pipe support design load was determined, and applicable feedwater system pipe supports were evaluated and demonstrated to be within design basis limits. The results of these evaluations are discussed in Section 2.2.2.2.3. The remaining BOP piping systems (i.e., condensate, extraction steam, feedwater heater vents and drains, MSR vents and drains) that experience slight flow rate increases have historically not experienced significant flow induced fluid transients. Hence, the flow rate increases for these systems can be concluded to be acceptable without further evaluation.

Changes in piping operating temperatures due to revised heat exchanger heat load requirements (e.g., component cooling and service water heat exchangers) have been addressed as part of the piping and support evaluations.

There were no changes to seismic inputs (amplified response spectra) or loads resulting from SPU. The existing seismic design basis for all piping and supports remain valid and unaffected by SPU. Hence, BOP piping and support seismic loadings will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-2.

For BOP piping and support systems that required detailed analyses to reconcile SPU operating parameters, a summary of revised stress levels corresponding to SPU conditions is provided in Table 2.2.2.2-1. The results presented include existing stress levels i.e., current, revised stress levels for SPU conditions, allowable stress for the applicable loading condition, and the resulting design margin for each piping analysis that was evaluated to reconcile SPU conditions. The design margin provided is based on the ratio of the calculated stress divided by the allowable stress.

The following computer programs were used in performing the BOP piping and pipe support evaluations. These computer programs are not described in the FSAR and were used to calculate stresses and loads using the appropriate equations from the ASME III and/or ANSI B31.1 Codes. Using an approved Quality Assurance Program, these programs have been verified and validated and shown to be accurate and acceptable for use in BOP piping and support applications.

NUPIPE-SWPC

The NUPIPE-SWPC program was used to perform detailed pipe stress analysis. This program is designed to perform analyses in accordance with the ASME B&PV Code, Section III Nuclear Power Plant Components and the ANSI/ASME B31.1 Power Piping Code.

PC-PREPS

PC-PREPS is a PC based computer program which performs a complete structural analysis, performing an AISC code check, weld qualification and baseplate/anchor bolt qualifications.

PILUG-PC

PILUG-PC is a PC based stress analysis program used to calculate stress intensity at the junction of a rectangular attachment perpendicular to round pipe.

Other evaluations of issues that potentially impact BOP piping and supports are addressed in the following LR sections.

- Protection against dynamic effects, including GDC-4 requirements, of pipe whip and discharging fluids – Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and Section 2.5.1.3, Pipe Failures.
- Protection against internally generated missiles and turbine missiles, including GDC-4 requirements, is discussed in Section 2.5.1.2, Missile Protection.
- Design of the Reactor Coolant System and related components, including GDC-15 requirements, is discussed in Section 2.2.2.1, NSSS Piping, Components and Supports, Class 1.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 License Renewal Safety Evaluation Report for BOP piping and supports. As stated in Section 2.2.2.2.1 BOP supports are within the scope of License Renewal. The aging evaluations approved by the NRC in NUREG 1838 for BOP piping and supports remain valid for SPU conditions.

With respect to the pipe support modifications for the recirculation spray, feedwater, condensate, and MSR vent and drain piping systems, the Design Change Process for these modifications will assess the impact on License Renewal system evaluation boundaries.

2.2.2.2.2.3 Results

The results of the evaluations of the BOP piping and support systems listed in Section 2.2.2.2.2.1 (Introduction) have determined that these systems remain acceptable for SPU conditions, with the exception of the recirculation spray, feedwater, condensate, and MSR vent and drain systems, which will require pipe support modifications to accommodate the revised loads due to SPU.

Table 2.2.2.2-1 provides a summary of existing stress levels (i.e., current), revised stress levels for SPU conditions, and the resulting design margins for each piping analysis that required detailed evaluation to reconcile SPU conditions. Piping systems not specifically listed in

Table 2.2.2.2-1 did not require detailed evaluation to reconcile SPU conditions or involve piping and support systems which will experience plant modifications. The stress results reported have incorporated thermal expansion and fluid transient increases, as applicable, that were reconciled as part of the SPU evaluations.

The piping stress evaluations performed conclude that all piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure and flow rate effects resulting from SPU conditions. The piping evaluations also concluded that the feedwater system can withstand water hammer loads associated with SPU conditions (resulting from a feedwater isolation valve closure/pump trip event) although several pipe support modifications will be required. Additionally, the main steam system was shown to be acceptable for steam hammer loads associated with the TSV/TCV fast closure event.

The results of the pipe support evaluations for systems impacted by SPU concluded that all supports remain acceptable, with the exception of several pipe supports on the recirculation spray, feedwater, condensate and MSR vent and drain piping systems which will require modification to accommodate the revised loads due to SPU.

The results of the equipment nozzle and containment penetration evaluations concluded that these components remain within acceptable limits for SPU conditions.

Additionally, the implementation of SPU will result in higher flow rates for several piping systems. Piping systems experiencing these higher flow rates (i.e., main steam, feedwater, condensate, extraction steam, feedwater heater vents and drains, MSR vents and drains) will be reviewed for potential vibration issues. Potentially affected piping will be included as part of the start-up testing program related to the overall implementation of SPU. Refer to Section 2.12 for discussion of the Power Ascension and Testing Plan.

2.2.2.2.3 Conclusion

DNC concludes that pipe stress levels for BOP piping will remain within allowable stress limits. DNC also concludes that all supports remain acceptable, with the exception of several pipe supports on the recirculation spray, feedwater, condensate and MSR vent and drain piping systems which will require modification to accommodate the revised loads due to SPU. Based on this, it is concluded that the pressure-retaining components and their supports will continue to meet the MPS3 current licensing basis with respect to the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14 and GDC-15. DNC finds the proposed SPU is acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

Table 2.2.2.2-1
Stress Summary at SPU Conditions

Piping Analysis Description	Loading Condition	Current Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Design Ratio (Note 1 & 2)
1st Point Extraction Steam Piping to 3FWS-E1A/B/C	Equation 13	17,671	19,261	22,431	0.86
2nd Point Extraction Steam Piping to 3CNM-E2A/B/C	Equation 13	21,361	21,788	22,500	0.97
3rd Point Extraction Steam Piping to 3CNM-E3C	Equation 13	17,322	19,401	22,500	0.86
4th Point Extraction Steam Piping to 3CNM-E4A	Equation 13	7,975	8,693	22,500	0.39
3rd Point Extraction Steam Piping to 3CNM-E3A	Equation 13	8,899	9,344	22,500	0.42
4th Point Extraction Steam Piping to 3CNM-E4B	Equation 13	10,578	11,530	22,500	0.51
3rd Point Extraction Steam Piping to 3CNM-E3B	Equation 13	12,077	12,681	22,500	0.56
4th Point Extraction Steam Piping to 3CNM-E4C	Equation 13	13,066	14,242	22,500	0.63
5th Point Extraction Steam Piping to 3CNM-E5A	Equation 13	14,082	14,927	22,500	0.66
6th Point Extraction Steam Piping to 3CNM-E6A	Equation 14	23,760	25,423	34,375	0.74
6th Point Extraction Steam Piping to 3CNM-E6A	Equation 13	14,208	15,203	20,625	0.74
Feedwater Piping – Loops B & C Inside Containment	Equation 9 (Upset)	13,049	14,354	18,000	0.80
	Equation 9 (Faulted)	12,810	14,091	36,000	0.39
Feedwater Piping – Loops A & D Inside Containment	Equation 9 (Upset)	15,470	17,017	18,000	0.95
	Equation 9 (Faulted)	15,276	16,804	36,000	0.47

Table 2.2.2.2-1
Stress Summary at SPU Conditions

Piping Analysis Description	Loading Condition	Current Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Design Ratio (Note 1 & 2)
Feedwater Piping – Turbine Building. (3FWS - E1C Outlet)	Equation 12 (Occasional) Normal/Upset (Mat. A106Gr.C)	10,822	11,904	21,000	0.57
	Equation 12 (Occasional) Faulted (Mat. A106Gr.C)	10,822	11,904	42,000	0.28
	Equation 12 (Occasional) Normal/Upset (Mat. A106Gr.B)	9,378	10,316	18,000	0.57
	Equation 12 (Occasional) Faulted (Mat. A106Gr.B)	9,378	10,316	36,000	0.29
Feedwater Piping – Turbine Building. (3FWS – E1A&B Outlet)	Equation 12 (Occasional) Normal/Upset	10,737	11,811	21,000	0.56
	Equation 12 (Occasional) Faulted	10,737	11,811	42000	0.28
Feedwater Piping Turbine Building to Containment Penetrations 5 & 6	Equation 9 (Occasional) Normal/Upset (Mat. A106Gr.C)	18,590	19,726	21,000	0.94
	Equation 9 (Occasional) Faulted (Mat. A106Gr.C)	18,249	20,074	42,000	0.48
	Equation 9 (Occasional) Normal/Upset (SA106Gr.B)	14,281	15,709	18,000	0.87
	Equation 9 (Occasional) Faulted (S A106Gr.B)	14,149	15,564	36,000	0.43

Table 2.2.2.2-1
Stress Summary at SPU Conditions

Piping Analysis Description	Loading Condition	Current Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Design Ratio (Note 1 & 2)
Feedwater Piping Turbine Building to Containment Penetrations 7 & 8	Equation 9 (Occasional) Normal/Upset (Mat. A106Gr.C)	20,489	20,323	21,000	0.97
	Equation 9 (Occasional) Faulted (Mat. A106Gr.C)	17,007	18,708	42,000	0.45
	Equation 9 (Occasional) Normal/Upset (SA106Gr.B)	14,131	15,544	18,000	0.86
	Equation 9 (Occasional) Faulted (S A106Gr.B)	14,064	15,470	36,000	0.43
Feedwater Piping – Turbine Building (Problem 1720)	Equation 13 (Thermal)	10,665	10,772	26,250	0.41
	Equation 12 (Occasional)	11,534	12,687	21,000	0.6
Condensate Piping – Turbine Building (4th – 5th Point Feedwater Heaters)	Equation 13 (Thermal)	4,074	5,052	22,500	0.23
Condensate piping – Turbine Building (2nd - 3rd Point Feedwater Heaters)	Equation 13 (Thermal)	12,865	14,666	22,500	0.65
Condensate piping – Turbine Building (To 6th & 5th Point Heaters)	Equation 13 (Thermal)	13,442	15,996	22,500	0.71
Condensate piping – Turbine Building (2nd Point Heaters to FW Pumps)	Equation 13 (Thermal) A106 Gr. B	14,165	15,865	22,500	0.71
	Equation 14 (Thermal + Sustained) A155 Gr55 Cl 1	33,575	33,911	34,250	0.99
Condensate Makeup and Draw Off piping – Turbine Building	Equation 14 (Thermal + Sustained)	19,307	27,104	37,500	0.73

Table 2.2.2.2-1
Stress Summary at SPU Conditions

Piping Analysis Description	Loading Condition	Current Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Design Ratio (Note 1 & 2)
Condensate Piping & LP Feedwater Heater Drains (Problem 1809)	Equation 13 (Thermal)	7,201	8,281	22,500	0.37
Moisture Separator and Heater Drain Tank Piping (Problem 2300)	Equation 13 (Thermal)	14,793	14,941	22,500	0.67
Moisture Separator and Heater Drain Tank Piping (Problem 2301)	Equation 14 (Thermal + Sustained)	34,102	34,983	37,500	0.93
Moisture Separator and Heater Drain Tank Piping (Problem 2302)	Equation 14 (Thermal + Sustained)	30,919	36,018	37,500	0.96
Moisture Separator and Heater Drain Tank Piping (Problem 2303)	Equation 14 (Thermal + Sustained)	22,552	24,807	37,500	0.66
Moisture Separator and Heater Drain Tank Piping (Problem 2304)	Equation 13 (Thermal)	14,864	15,013	22,500	0.67
Moisture Separator and Heater Drain Tank Piping (Problem 2305)	Equation 13 (Thermal)	13,548	14,903	22,500	0.66
Moisture Separator and Heater Drain Tank Piping Problem 2306)	Equation 13 (Thermal)	20,195	20,397	22,500	0.91
Moisture Separator and Heater Drain Tank Piping Problem 2308)	Equation 13 (Thermal)	17,894	18,073	22,500	0.80
3FWS – E1A/B/C Relief piping	Equation 13 (Thermal)	12,259	12,382	22,500	0.55
3CNM – E2A/B/C Relief Piping	Equation 13 (Thermal)	14,869	18,438	22,500	0.82

Table 2.2.2.2-1
Stress Summary at SPU Conditions

Piping Analysis Description	Loading Condition	Current Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Design Ratio (Note 1 & 2)
3CNM – E4A/B/C Relief Piping	Equation 13 (Thermal)	4,539	4,584	22,500	0.20

NOTES:
(1) Design Ratio reported is based on the ratio of SPU stress/Allowable stress.
(2) With respect to piping analyses containing design margins greater than 0.90 for SPU conditions, it should be noted that the existing design margins (for the same loading condition) for all these piping analyses, with the single exception of feedwater piping (Loops A&D) inside containment, are currently greater than 0.90. For example, the 2nd point extraction steam piping to 3CNM-E2A/B/C has a reported design margin of 0.97 based on the ratio of 21,788 (SPU stress) divided by 22,500 (allowable stress). The existing design margin for this piping is 0.95 based on the ratio of 21,361 (current stress) divided by 22,500 (allowable stress). Hence, for this piping system, the actual stress increase resulting from SPU is not that significant. Additionally, all stress levels resulting in design margins less than or equal to 1.0 are acceptable limits in accordance with AMSE III and ANSI B31.1 codes of record. The allowable stress levels for these codes are stress levels that are well below material yield and/or ultimate stress limits.

2.2.2.3 Reactor Vessel and Supports

2.2.2.3.1 Introduction

The RPV and its supports are reviewed as part of the SPU. The RPV is described in FSAR Sections 4.1, 3.9N.1.1 and 5.3. The RPV supports are described in FSAR Sections 3.9N.1.4.3 and 5.4.14.1. The Regulatory Evaluation included in Section 2.2.2 also applies to the RPV and its supports.

The RPV, as the principal component of the RCS, contains the heat-generating core and associated supports, controls, and instrumentation, and coolant circulating channels. Primary outlet and inlet nozzles provide for the exit of heated coolant and its return to the RPV for recirculation through the core.

The Technical Evaluation included as part of this LR describes the input parameters, assumptions and acceptance criteria used to evaluate RPV and RPV support performance relative to the SPU.

A summary regarding the adequacy of the RPV and its supports under SPU conditions concludes this LR subsection.

Current Licensing Basis

The generic CLB in Section 2.2.2 applies to the RPV and its supports, with the following amplifications.

The MPS3 RPV is cylindrical, with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. The vessel contains the core, core support structures, control rods, and other components directly associated with the core.

The vessel has inlet and outlet nozzles located in a horizontal plane below the RPV flange but above the top of the core. Coolant enters the vessel through the inlet nozzles, flows down the core barrel-vessel wall annulus, and is then redirected at the bottom to flow up through the core and out the outlet nozzles.

FSAR Section 5.3.1 states in part that all pressure boundary materials used in the RPV are selected and fabricated in accordance with the requirements of Section III of the ASME Code. FSAR Table 5.2-1 provides ASME B&PV Code Edition and Addenda applicable to the RPV. A general discussion of materials specifications is given in FSAR Section 5.2.3, with types of materials listed in FSAR Tables 5.2-2 and 5.2-3.

FSAR Section 5.3.1 states in part that:

- The RPV is Safety Class 1. Design and fabrication of the RPV was carried out in strict accordance with the ASME Code, Section III, Class 1 requirements.
- The head flange and nozzles were manufactured as forgings. The cylindrical portion of the vessel is made up of several shells, each consisting of formed plates joined by full penetration longitudinal weld seams. The hemispherical heads were made with dished plates. The integral parts of the vessel and closure head subassemblies were joined by welding, primarily using the single or multiple wire submerged arc process.

The RPV and RPV supports are designed to withstand stresses originating from various operating design transients described in FSAR Section 3.9N.1.1 and FSAR Table 5.4-18. The RPV supports are designed to meet the same Safety Class designation as the components they support. The RPV supports are classified as QA Category 1 and Seismic Category I, as stated in FSAR Table 3.2-1.

FSAR Section 5.4.14.1.1 states in part that:

- The support for the RPV (the neutron shield tank) is a cylindrical, double-wall structure that surrounds and supports the RPV, and accommodates all applicable loading conditions. The RVSS transfers all loading conditions from the RPV to the primary shield wall through groutings, and to the concrete anchors at its base. The RVSS also provides support for the out-of-core neutron detector monitors.
- The annular portion of the tank is filled with water to provide neutron shielding and a thermal barrier for protection of the surrounding structural concrete. The water is circulated through an external heat exchanger to maintain proper cooling for the system.
- The RPV is supported at four nozzles on leveling devices mounted on top of the neutron shield tank. The functional requirement of the RPV leveling devices is to provide vertical adjustment at each RPV nozzle restraint pad during installation of the RPV. During all plant conditions, the leveling device is designed to transfer only downward vertical loads from the RPV to the RVSS. Upward and side loads from the RPV are resisted by gib keys and gib gussets. The RVSS is shown in FSAR Figures 5.4-9 and 5.4-10.

FSAR Table 3.9N-1 summarizes RCS design transients. It states that the RPV is designed for 200 heat up transients of 100°F per hour, and an additional 200 cool down transients of 100°F per hour.

FSAR Table 5.4-15 provides the RPV design data. The ability of the pressure boundary components to perform throughout the design lifetime as defined in the design specification is confirmed by the stress analysis report required by the ASME Code, Section III.

The MPS3 RPVP is inspected per the requirements of Section XI of the ASME B&PV Code, 1989 Edition, no addenda.

The MPS3 RPV and its supports were evaluated for continued acceptability regarding plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, documents the results of that review. NUREG-1838, Sections 2.3B.1.1 and 3.1B are applicable to the RPV. NUREG-1838 Sections 2.4B.3 and 3.5B are applicable to the RPV supports.

NUREG-1838, Appendix A, Commitments for License Renewal of MPS3, Items 15, 28 and 29, present commitments concerning license renewal regarding pressure retaining components and component supports, as they apply to the RPV and associated supports.

2.2.2.3.2 Technical Evaluation

2.2.2.3.2.1 Introduction

To ensure adequacy of the Reactor Vessel and Supports for SPU conditions, evaluations were performed for the revised operating conditions, including pressure, temperature, transient effects, and LOCA loads.

2.2.2.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The analyses and evaluations performed as documented in the structural report for the vessel components and supports incorporate into the original reactor vessel stress report, which was prepared by Combustion Engineering, the revised operating temperatures, RCS transients, and revised seismic and LOCA reactor vessel/internals interface loads associated with the MPS3 SPU.

Analysis of flow induced vibration for the reactor vessel and supports is not included in the licensing basis for MPS3. Reactor vessel components are considered unaffected by SPU conditions due to their heavy construction and the fact that the MDF for the SPU conditions continues to be unchanged at 103,000 gpm.

Presented in the structural report are the analyses and evaluations necessary per Section III of the ASME Boiler and Pressure Vessel Code to substantiate the structural adequacy of the MPS3 reactor vessel for operation under SPU conditions.

Revised maximum stress intensity ranges and cumulative fatigue usage factors were calculated and compared to the following acceptance criteria:

1. The maximum range of primary-plus-secondary stress intensity resulting from mechanical and thermal loads shall not exceed $3S_m$ at operating temperature. In addition to the above, in the event the primary-plus-secondary stress intensity resulting from mechanical and thermal loads exceeds the $3S_m$ acceptance criteria, the design shall be considered acceptable if the criteria specified for a simplified elastic-plastic analysis per Section NB-3228.3 of the ASME B&PV Code, Section III, Division 1 1971 Edition through Summer 1973 Addenda can be met.

2. The maximum cumulative usage factor resulting from the peak stress intensities due to the normal and upset condition design transient mechanical and thermal loads cannot exceed 1.0 in accordance with the procedure outlined in the ASME B&PV Code, Section III, Division 1, 1971 Edition, with Addenda through Summer 1973.

2.2.2.3.2.3 Assumptions

The following assumption was made in performing the evaluations of the reactor vessel components:

The MPS3 reactor vessel components are essentially identical to those for the Seabrook Unit. The validity of this assumption was verified by detailed comparison of the drawings for the two units. This assumption allowed certain evaluations performed for Seabrook to be applied to MPS3.

2.2.2.3.2.4 Description of Analyses and Evaluations

The structural report updates the stress intensities and fatigue usage factors of the closure head and main closure region components based on the SPU operating conditions.

For the evaluation of the MPS3 reactor vessel components, a graphical transient comparison was first performed in which the revised RCS design transients for the MPS3 SPU were compared to those for the existing qualification. Revised MPS3 SPU RCS design transients found to be more severe than the existing qualification were then compared to those for an essentially identical reactor vessel evaluated for a similar uprate program. In all cases, the new transient data for the MPS3 SPU was found to be covered either by the existing qualification and/or by the prior similar uprate program (Reference 1).

The temperature and pressure transient information for the MPS3 SPU were reviewed and found in all cases to be bounded by either the existing qualification, or by a similar uprate qualification.

The stress intensities for those transients that were deemed more severe than their baseline counterparts were examined to determine their effect on the maximum ranges of stress intensity for all the regions of the reactor vessel. The changes in the thermal and pressure stresses, due to variations from the baseline transients, were evaluated using standard engineering approaches. The incremental thermal and pressure stress changes were then factored into stress intensities which are documented in the baseline stress report(s), and the effects of the changes on the maximum ranges of stress intensity were observed and also documented in stress report addenda.

The peak stress intensity ranges for the fatigue evaluation were also adjusted to account for the incremental thermal and pressure stress changes caused by changes from the baseline transients. The peak thermal and pressure stresses were multiplied by the appropriate scaling factor, where necessary, before determining a new peak stress intensity range and finally an alternating stress. The allowable number of cycles of alternating stress was found from the applicable fatigue curve in the ASME B&PV Code, Section III, Division 1, 1971 Edition through Summer 1973 Addenda, and the cumulative fatigue usage factors were revised accordingly.

Where applicable, the maximum and minimum stress intensity ranges and fatigue usage factors were revised to reflect the presented changes to the baseline transients. In other cases, the baseline stress analysis in the baseline stress report remained conservative with regard to the design transients and new calculations were not necessary. For those cases, the maximum stress intensity ranges and fatigue usage factors reported in the baseline reactor vessel stress report were not changed.

Seismic and LOCA reactor vessel/internals interface loads for the SPU were reviewed for the barrel outlet nozzle and lower radial interfaces. A comparison of these loads and the allowable loads defined was performed as part of the reactor vessel evaluation. All of the loads were found to be bounded by existing MPS3 analyses, and no additional load evaluation was required.

With respect to the reactor vessel supports, the reactor vessel nozzle loads and reactor vessel support reaction loads are not impacted by the SPU. The existing design basis calculations that perform the qualification and demonstrate the acceptability of the reactor vessel nozzle loads and the reactor vessel support loads consider bounding loads that envelop loads associated with and resulting from SPU.

Impact On Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal Application for the reactor vessel and vessel supports. The aging evaluations approved by the NRC in NUREG-1838 for the reactor vessel and supports remain valid for SPU conditions.

In addition, the evaluations (summarized in this section) of maximum stress intensity ranges and cumulative fatigue usage factors for the components of the reactor vessel, considering SPU conditions, show that the reactor vessel components continue to meet the ASME acceptable limits. The number of transient cycles have not been scaled up or increased in going from 40 years to 60 years, so the 40 year design transients apply to 60 years operation. Since the original 40-year design transient set has been shown to be bounding for 60 years of operation based on the finding that the number of original design cycles bounds the actual plant cycles, and the number of design cycles for the SPU has not changed from the original 40-year transient set, the fatigue evaluations of the reactor vessel components are valid for 60 years of operation.

2.2.2.3.2.5 Results

Based upon the reactor vessel evaluations outlined in this report, all of the maximum ranges of primary-plus-secondary stress intensity and maximum cumulative fatigue usage factors for the MPS3 reactor vessel components listed in Table 2.2.2.3-1 through 2.2.2.3-3 continue to satisfy the applicable limits of ASME B&PV Code, Section III, Division 1, 1971 Edition through Summer 1973 Addenda:

The maximum ranges of stress intensity and maximum cumulative fatigue usage factors from the reactor vessel evaluation are shown in Table 2.2.2.3-1. The seismic and LOCA vessel-to-internals interface loads are shown and evaluated in Table 2.2.2.3-2, and the CRDM housing moments are shown and evaluated in Table 2.2.2.3-3. All of the loads due to the SPU are less than the allowable or limiting loads.

The reactor vessel/internals interface loads are below the previously qualified allowable loads.

With respect to the reactor vessel supports, the reactor vessel nozzle loads and reactor vessel support reaction loads are not impacted by the SPU. The existing design basis calculations that perform the qualification and demonstrate the acceptability of the reactor vessel nozzle loads and the reactor vessel support loads consider bounding loads that envelop loads associated with and resulting from SPU.

2.2.2.3.3 Conclusion

DNC has reviewed the evaluations related to the structural integrity of the reactor vessel and vessel supports and concludes that the evaluations have adequately addressed the effects of the proposed SPU on the reactor vessel and vessel supports. DNC further concludes that the evaluations have demonstrated that the reactor vessel and vessel supports continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14 and GDC-15 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the design of the reactor vessel and vessel supports.

2.2.2.3.4 References

1. Seabrook Station, Unit No. 1- Issuance of Amendment re: 5.2 Percent Power Uprate (TAC NO. MC2364), February 28,2005.

Table 2.2.2.3-1
Maximum Range of Stress Intensity and Cumulative Fatigue Usage Factors

LOCATION	MAXIMUM RANGE OF STRESS INTENSITY	CUMULATIVE FATIGUE USAGE FACTOR
Head Flange, Vessel Flange & Closure Studs	**Closure Head Flange** 50.82 ksi < $3S_m$ = 80.1 ksi **Vessel Flange** 44.63 ksi < $3S_m$ = 80.1 ksi **Closure Studs** 88.55 ksi < $3S_m$ = 123.6 ksi	**Head Flange** 0.0155 < 1.0 **Vessel Flange** 0.0196 < 1.0 **Closure Studs** 0.4780 < 1.0
Bottom Head to Shell Juncture	49.9 ksi < $3S_m$ = 80.1 ksi	0.0070 < 1.0
Vessel Wall Transition	56.1 ksi < $3S_m$ = 80.1 ksi	0.0116 < 1.0
Inlet Nozzle & Support Pad	**Inlet Nozzle** Safe End: 43.0 ksi < $3S_m$ = 52.1 ksi Nozzle: 63.11 ksi < $3S_m$ = 80.1 ksi	**Inlet Nozzle** 0.0742 < 1.0
	Support Pad 75.51 ksi < $3S_m$ = 80.1 ksi	**Support Pad** 0.085 < 1.0
Outlet Nozzle & Support Pad	**Outlet Nozzle** Safe End: 48.75 ksi < $3S_m$ = 53.7 ksi Nozzle: 67.62 ksi < $3S_m$ = 80.1 ksi	**Outlet Nozzle** 0.1011 < 1.0
	Support Pad 61.64 ksi < $3S_m$ = 80.1 ksi	**Support Pad** 0.0476 < 1.0
CRDM Housings	59.0 ksi < $3S_m$ = 69.9 ksi	0.1093 < 1.0
Bottom Head Instrument Tubes	**Location 1* #** 70.67 ksi > $3S_m$ = 69.9 ksi	**Location 1 #** 0.0014 < 1.0
	Location 2 # 58.93 ksi < $3S_m$ = 69.9 ksi	**Location 2 #** 0.3184 < 1.0
Core Support Lugs	60.55 ksi < $3S_m$ = 80.1 ksi	0.0627 < 1.0
Head Adapter Plugs	27.6 ksi < $3S_m$ = 48.6 ksi	0.0036 < 1.0

*Note: Exceeded 3 Sm limit, simplified elastic-plastic analysis was performed to calculate fatigue strength, as allowed by ASME, B&PV Code, Section III, NB 3228.5. These conditions have been met and the fatigue usage is less than 1.0. This is a pre-SPU condition.

Note: Location 1 is at the extreme lower level of the tube-to-vessel ID weld on the tube inside diameter. Location 2 is at the same elevation at the tube Outside diameter

Table 2.2.2.3-2
Reactor Vessel/Internals Interface Loads (lb)

Location	LOCA Interface load, lb	Seismic Interface Load, lb.	SRSS (Seismic+LOCA) lb	LIMIT, lb	IS SRSS < LIMIT?
Vessel-Barrel Flange	0	2,264,000	2,264,000	6,040,000	YES
Horizontal					
Vessel-Barrel Flange	1,810,968	4,130,000	4,509,601	7,572,000	YES
Vertical					
Vessel-Upper Support Plate	108,054	180,000	209,942	1,284,000	YES
Flange Horizontal					
Vessel-Upper Support Plate	1,458,798	2,900,000	3,246,243	3,457,000	YES
Flange Vertical					
Core Barrel Outlet Nozzle	24,351	1,010,000	1,010,294	1,052,000	YES
Lower Radial Keys	692,402	950,000	1,175,551	5,661,178	YES
(Core Support Lugs)					

Table 2.2.2.3-3
Reactor Vessel CRDM Housings Applied Moments

Location	LOCA Interface load in-lb	Seismic Interface Load, in-lb.	SRSS (SSE+LOCA) in-lb	LIMIT in-lb	IS SRSS < LIMIT?
Head Adapter (SS)	70,036	102,468	124,116	212,000	YES
Head Adapter (Inconel)	91,342	137,380	164,975	240,000	YES

2.2.2.4 Control Rod Drive Mechanism

2.2.2.4.1 Introduction

The evaluation of the MPS3 CRDM is an assessment of the impact on the structural integrity of the assemblies from the thermal transients and maximum operating temperatures and pressures that result from the proposed SPU operating conditions. The pressure-retaining components and component supports, including the CRDM, are reviewed as part of the SPU.

The DNC review focused on the CRDM pressure vessel assembly. Other CRDM subassemblies are addressed by other licensing report sections and are evaluated under different criteria, as appropriate.

The DNC review covered the ability of the pressure retaining sections of the CRDM to meet applicable GDC. This review addressed material compatibility with primary system fluids and design of the CRDM equipment, which is part of the RCPB, to meet applicable design transients. The review addressed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the ASME B&PV Code, Section III, Division 1, 1974 Edition through Summer 1974 Addenda, for normal, upset, emergency and faulted conditions. The DNC Review also covered the analyses of flow induced vibration and the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses.

Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1 and other guidance provided in Matrix 2 of RS-001.

MPS3 Current Licensing Basis

The generic CLB in Section 2.2.2 applies to the CRDM. The CLB Section 2.2.2 describes the GDC and related guidance applicable to this review of RCS pressure retaining components and component supports (CRDMs, Pressurizer, RCPs, RV Structure, SGs). Those are: 10 CFR 50.55a and GDC-1; and GDC-2, -4, -14 and -15.

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800) and SRP Sections 3.9.1 (Rev. 2), 3.9.2 (Rev. 2), 3.9.3 (Rev. 1) and 5.2.1.1 (Rev. 1). As noted in the FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

FSAR Section 3.9N.4.1 states that CRDMs are located on the dome of the RV head. They are coupled to RCCAs which have neutron absorber material over the entire length of the control rods and derive their name from this feature. The primary function of the CRDM is to insert, withdraw or hold stationary, RCCAs within the core to control average core temperature and to shutdown the reactor.

The CRDM consists of four separate subassemblies. They are the pressure vessel, coil stack assembly, latch assembly, and the drive rod assembly. The CRDM is threaded and seal welded on a head adaptor on top of the RV head. The drive assembly is coupled to the RCCA directly below.

The pressure vessel assembly includes a latch housing and a rod travel housing which are connected by a threaded, seal welded maintenance joint, which facilitates replacement of the latch assembly. The closure at the top of the rod travel housing is a threaded cap with a canopy seal weld for pressure integrity. Seismic support of the CRDM is attained by the spacer plates of the rod position indicator coil stack assembly and the seismic support ring.

The latch housing is the lower portion of the pressure vessel and encloses the latch assembly. The rod travel housing is the upper portion of the pressure vessel and provides space for the drive rod assembly during this upper movement as the control rods are withdrawn from the core.

The pressure vessel component of the CRDM assembly constitutes a portion of the RCPB. The pressure boundary of the CRDMs and all the components of the CRDS are designed as Seismic Category I equipment (FSAR Table 3.2-1). MPS3 uses Westinghouse Model L-106A CRDMs. The CRDMs currently in use are the original components supplied for MPS3.

The CRDM is designed to withstand stresses originating from various operating design transients (See FSAR Table 3.9N-1). Structural evaluation performed on CRDM pressure retaining components consider the loading combinations specified in FSAR Table 3.9N-2.

The ability of the pressure housing components to perform throughout the design lifetime as defined in the design specification is confirmed by the stress analysis report required by the ASME Code, Section III.

FSAR Section 3.9N.4.4 describes testing performed on the CRDMs and RCCAs. It is expected that all CRDMs will meet specified operating requirements for the duration of plant life with normal refurbishment. Functional tests performed on CRDMs and RCCAs have been reported in Westinghouse reports WCAP-8446 and WCAP-8449. Actual experience in operating Westinghouse plants indicates excellent performance of CRDMs.

FSAR Chapter 4.5.1.1 discusses the specific materials used for the Control Rod System which are subject to contact with the reactor coolant. FSAR Table 5.2-2 contains the materials specifications for the material used in the CRDM head adaptor and upper head.

FSAR Section 3.9N.4.2 states that the CRDM pressure housings are Class 1 components designed to meet the stress requirements for normal operating conditions of Section III of the ASME B&PV Code. Both static and alternating stress intensities are considered. The stresses originating from the required design transients are included in the analysis.

The CRDM was evaluated for continued acceptability to support license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005. NUREG 1838, Section 2.3B.1.1 is applicable to the CRDM.

2.2.2.4.2 Technical Evaluation

2.2.2.4.2.1 Input Parameters, Assumptions, and Acceptance Criteria

The model L-106A CRDMs are designed and analyzed to meet the requirements of the ASME B&PV Code, Section III, Division 1, 1974 Edition through Summer 1974 Addenda. Generic and plant specific analyses for model L-106A CRDMs were the basis for this evaluation. The NSSS operating parameters and NSSS design transients developed for the MPS3 SPU were used as the new inputs for this evaluation. The seismic loading has not been changed for the MPS3 SPU program. The MPS3 CRDMs are of the hot reactor vessel head type, defined by the vessel outlet reactor coolant temperature, T_{Hot}, in Section 1.1, Table 1-1, NSSS PCWG Parameters for the MPS3 SPU Program. Therefore, this analysis assumes that the NSSS design transients are defined for the hot leg.

The acceptance criteria for the ASME Code structural analysis of the CRDM reactor coolant pressure boundary are that the analyzed stresses do not exceed the allowable stresses of the ASME Code, and that the cumulative fatigue usage factors from the code fatigue analysis do not exceed 1.0. For those cases for which changes to the design transients would have allowed a decrease in stresses or cumulative usage factors, no decrease was calculated, and no credit was taken for such a decrease. Since the CRDM reactor coolant pressure boundary is located on the Reactor Vessel Head, it experiences no flow induced vibration.

2.2.2.4.2.2 Description of Analyses and Evaluations

2.2.2.4.2.2.1 Operating Pressure and Temperature

The NSSS temperatures and pressures developed for the MPS3 SPU program (as given in Section 1.1, Table 1-1, NSSS PCWG Parameters for the MPS3 SPU Program) were compared to those used for the generic model L-106A CRDMs design and analysis. There is no change in the reactor coolant pressure of 2250 psia for any SPU cases. The hot leg temperature (T_{Hot}), defined by the vessel outlet temperature, is a maximum of 622.6°F. This temperature is less than the 650.0°F temperature used in the generic analysis for model L-106A CRDMs. Since none of the temperatures exceed the previously analyzed temperature and the pressure does not change, the NSSS parameters developed for the SPU program and used for this evaluation are bounded by the generic analyses model L-106A CRDMs.

2.2.2.4.2.2.2 Transient Discussion

The NSSS design thermal transients, discussed in Section 2.2.6, NSSS Design Transients, were not significantly different from those used to analyze the generic model L-106A CRDMs. The differences are:

- Two transients discussed in Section 2.2.6 are not specified in the existing design basis L-106A CRDM analyses.
- There are temperature and pressure range differences between the SPU and existing design basis NSSS design transients

The impact these changes had on the stress intensities were analyzed using the generic stress report methodology and are acceptable for the Millstone SPU program.

2.2.2.4.2.2.3 Assessment of CRDM Material Degradation

An assessment of the potential degradation of pressure boundary materials in the CRDM has been performed to address issues arising from the SPU at MPS3. The primary concern from the SPU is the potential impact of changes to the normal operating temperatures in the reactor coolant system on material integrity during service. These changes include general corrosion and stress corrosion cracking of system materials.

The minor change in the CRDM's normal operating temperature has no effect on the general corrosion rate of the CRDM pressure boundary materials. Two additional degradation mechanisms with the potential to affect austenitic stainless steels are intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC). Sensitized microstructure and the presence of oxygen are required for the occurrence of IGSCC. The introduction of halogens, such as chlorides, and the presence of oxygen are prerequisites for the occurrence of TGSCC. The minor change in the CRDM's normal operating temperature has no effect on either of these mechanisms. Primary water chemistry limits for MPS3 prevent the introduction of any of these contributors; therefore, no impact on material degradation is expected in austenitic stainless steel CRDM components as a result of the proposed SPU.

Based upon this assessment, the change in the CRDM's normal operating temperature due to the SPU for MPS3 has no detrimental effect with respect to potential degradation mechanisms for the CRDM pressure boundary materials.

2.2.2.4.2.2.4 Impact On Renewed Plant Operating License Evaluations and License Renewal

The MPS3 SPU does not require any new components or introduce any new functions for existing CRDM components that would require revision of the license renewal system evaluation boundaries. The operation of the CRDM at SPU conditions does not result in any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.2.2.4.2.3 Results

A summary of the results of the evaluations performed for the SPU is presented in Table 2.2.2.4-1 through 2.2.2.4-4. The changes in calculated stress intensities were proven acceptable for the MPS3 SPU operating conditions. The calculated stresses in all but two pressure vessel parts of the CRDMs meet the allowable ASME stress limits. The two cases were determined to be acceptable based on the following:

The maximum Upper Joint Bell Mouthing stress intensity of 19,639 psi exceeded the allowable yield strength, S_y by 160 psi. This is acceptable due to the conservatism of using the maximum design temperature of 650°F as opposed to the hot leg temperature, T_{Hot}, of 622.6°F, for the hot boundary of the steady state transient. The ASME Code allowable S_y is

19,479 psi at the nodal temperature of 494°F. Reducing the nodal temperature by the ratio (622.6/650) to 473°F yields an allowable S_y of 19,749 psi.

The maximum Lower Joint Canopy primary plus secondary stress intensity of 45,985 psi exceeded the allowable by 85 psi. This is considered insignificant due to the conservatism that the allowable is based on the design temperature of 650°F as opposed to the actual nodal temperature or 78°F. The ASME Code allowable stress intensity S_m is 20 ksi at 78°F and 15.3 ksi at 650°F.

The calculated cumulative usage factors are given in Table 2.2.2.4-4, and remain bounded for the SPU program. The highest cumulative usage factor (0.938) was calculated at the upper joint canopy. The usage factor was calculated in a conservative manner. The applied transients were grouped and the allowable number of cycles considered for each group was based on the most severe transient in the group.

The faulted condition maximum bending moments are compared to the allowable bending moments in Table 2.2.2.4-5 for the CRDM components and the CRDM head adapter. The maximum bending moments shown are square roots of the sum of the squares (SRSS) of the LOCA and the safe shutdown earthquake (SSE) bending moments. The LOCA loads are the maximum for any of the following three breaks: accumulator line break, pressurizer surge line break, and residual heat removal line break. All maximum faulted condition bending moments are below the allowable limits.

2.2.2.4.3 Conclusion

DNC has reviewed the evaluation related to the structural integrity of pressure-retaining components of the CRDM. For the previously presented reasons, DNC concluded that the effects of the proposed SPU on these components have been adequately addressed. DNC further concluded that, following implementation of the proposed SPU, these pressure retaining components continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15. Therefore, DNC found the proposed SPU, with respect to the structural integrity of the pressure-retaining components, acceptable.

Table 2.2.2.4-1
Upper Joint Components' Stress Summary

Upper Joint		Design Condition		Normal Condition		Upset Condition		Testing Condition		Special Condition		Faulted Condition	
Component	Param. Per ASME Code III	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)
Cap	P_m	5,954	16,100					7,400	16,110			7,216	19,320
	P_{m+} P_b	20,757	24,150					22,212	24,165			22,028	28,980
	P_{m+} P_{b+Q}			19,107	48,300	19,128	48,300						
	$\sigma_1+\sigma_2+\sigma_3$									-16,522	64,400		
Rod Travel Housing	P_m	14,172	16,100					17,613	21,420			17,176	19,320
	P_{m+} P_b	19,419	24,150					20,826	21,130			20,389	28,980
	P_{m+} P_{b+Q}			23,574	48,300	21,106	48,300						
	$\sigma_1+\sigma_2+\sigma_3$									13,922	64,400		
Canopy	P_m	4,606	16,100					5,724	16,110			5,582	19,380
	P_{m+} P_b	8,254	24,150					9,372	24,265			9,230	28,980
	P_{m+} P_{b+Q}			27,594	48,300	40,057	48,300						
	$\sigma_1+\sigma_2+\sigma_3$									9,667	64,400		

Table 2.2.2.4-1
Upper Joint Components' Stress Summary

Upper Joint		Design Condition		Normal Condition		Upset Condition		Testing Condition		Special Condition		Faulted Condition	
Component	Param. Per ASME Code III	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)
Threaded Area	Pm (Shear)									5,370	9,660		
	2x Shear									38,020	48,300		
	P_{m+} P_{b+Q}									47,500	48,300		
	Bell Mouthing Stress Intensity			19,639 Note 1	19,479	20,187	21,755						

Note 1: This stress exceeds the allowable by 160 psi. This is considered acceptable due to the conservatism that the maximum design temperature of 650°F was used, as opposed to the hot leg temperature of 622.6°F, for the hot boundary of the steady state transient. The ASME Code allowable yield strength, S_y, is 19,479 psi at the nodal temperature of 494°F. Reducing the nodal temperature by the ratio (622.6/650) to 473°F yields an allowable S_y of 19,749 psi.

Note 2: Shaded sections indicate inapplicability.

Table 2.2.2.4-2
Middle Joint Components' Stress Summary

Middle Joint		Design Condition		Normal Condition		Upset Condition		Testing Condition		Special Condition		Faulted Condition	
Component	Param. Per ASME Code III	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)
Rod Travel Housing	P_m	6,288	16,100					7,815	16,110			7,621	19,320
	P_{m+} P_b	8,172	24,150					9,669	24,165			9,505	28,980
	P_{m+} P_{b+Q}			16,669	48,300	14,388	48,300						
	$\sigma_1 + \sigma_2 + \sigma_3$									-14,654	64,400		
Latch Housing	P_m	11,930	15,300					14,827	15,300			14,459	18,360
	P_{m+} P_b	15,659	22,950					18,556	22,950			18,188	27,540
	P_{m+} P_{b+Q}			17,431	45,900	16,395	45,900						
	$\sigma_1 + \sigma_2 + \sigma_3$									15,056	61,200		
Canopy	P_m	4,460	15,300					5,543	15,300			5,406	18,360
	P_{m+} P_b	6,844	22,950					7,927	22,950			7,790	27,540
	P_{m+} P_{b+Q}			45,504	45,900	38,164	45,900						
	$\sigma_1 + \sigma_2 + \sigma_3$									5,439	61,200		

Table 2.2.2.4-2
Middle Joint Components' Stress Summary

Middle Joint		**Design Condition**		**Normal Condition**		**Upset Condition**		**Testing Condition**		**Special Condition**		**Faulted Condition**	
Threaded Area	Pm (Shear)									3,314	9,180		
	2x Shear									11,272	45,900		
	P_{m+} P_{b+Q}									31,100	45,900		
	Bell Mouthing Stress Intensity			14,136	17,000	11,069	17,000						

Note: Shaded sections indicate inapplicability.

Table 2.2.2.4-3
Lower Joint Components' Stress Summary

Middle Joint		Design Condition		Normal Condition		Upset Condition		Testing Condition		Special Condition		Faulted Condition	
Component	Param. Per ASME Code III	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)	Calc (psi)	Allow (psi)
Latch Housing	P_m	12,380	15,300					15,386	21,375			15,005	18,360
	P_{m+} P_b	16,650	22,950					19,656	32,062			19,275	27,540
	P_{m+} P_{b+Q}			16,921	45,900	15,228	45,900						
	$\sigma_1 +$ $\sigma_2 +$ σ_3									15,560	61,200		
Head Adaptor	P_m	7,343	16,100					9,126	16,100			8,900	19,320
	P_{m+} P_b	10,070	24,150					11,853	24,165			11,627	28,980
	P_{m+} P_{b+Q}			15,165	48,300	13,467	48,300						
	$\sigma_1 +$ $\sigma_2 +$ σ_3									15,824	64,400		
Canopy	P_m	9,345	15,300					11,614	15,300			11,326	18,360
	P_{m+} P_b	19,011	22,950					21,280	22,950			20,992	27,540
	P_{m+} P_{b+Q}			45,985 Note 1	45,900	37,560	45,900						
	$\sigma_1 +$ $\sigma_2 +$ σ_3									28,702	61,200		

Table 2.2.2.4-3
Lower Joint Components' Stress Summary

Middle Joint		Design Condition		Normal Condition		Upset Condition		Testing Condition		Special Condition		Faulted Condition	
Threaded Area	Pm (Shear)									4,103	9,180		
	2x Shear									12,852	45,900		
	P_{m+} P_{b+Q}									33,200	45,900		
	Bell Mouthing Stress Intensity			13,733	17,000	9,720	17,000						

Note 1: This stress exceeds the allowable by 85 psi. This is considered insignificant due to the conservatism that the allowable is based on the design temperature of 650°F as opposed to the actual nodal temperature or 78°F. The ASME Code allowable stress intensity S_m is 20 ksi at 78°F and 15.3 ksi at 650°F.

Note 2: Shaded sections indicate inapplicability.

Table 2.2.2.4-4 Cumulative Fatigue Usage Factors for CRDM Joints

Joint	Component	Total Usage Factor	Allowable Usage Factor
UPPER	Cap	0.0	1.0
	Road Travel Housing	0.0	1.0
	Canopy	0.938	1.0
	Weld Canopy	0.527	1.0
	Threaded Area	0.362	1.0
MIDDLE	Road Travel Housing	0.0	1.0
	Latch Housing	0.0	1.0
	Canopy	0.0	1.0
	Weld Canopy	0.524	1.0
	Threaded Area	0.039	1.0
LOWER	Latch Housing	0.0	1.0
	Head Adaptor	0.0	1.0
	Canopy	0.011	1.0
	Weld Canopy	0.027	1.0
	Threaded Area	0.031	1.0

Table 2.2.2.4-5
Bending Moment Summary for Faulted Conditions

	SSE (in-lb)	LOCA (in-lb)	Faulted[1] (in-lb)	Allowable (in-lb)	Margin[2]
Rod Travel Housing	64,754	77,734	101,171	232,301	56%
Latch Housing	95,873	147,492	175,913	808,005	78%
Head Adapter (SS)	102,468	70,036	124,116	212,000	41%
Head Adapter (Inconel)	137,380	91,342	164,975	240,000	31%

1. The Faulted value is calculated as SRSS= $(SSE^2 + LOCA^2)^{0.5}$
2. The margin is calculated as Margin= (Allowable – Faulted)/Allowable

2.2.2.5 Steam Generators and Supports

2.2.2.5.1 Introduction

The SGs and associated supports are reviewed as part of the SPU. The SGs are described in FSAR Sections 3.9N, 5.1 and 5.4.2. The SG supports are described in FSAR Section 5.4.14.1.2. MPS3 uses four Westinghouse Model F SGs. The Regulatory Evaluation included in Section 2.2.2 also applies to the SGs and supports.

The SG and supports evaluation was performed as eleven separate, but coordinated, evaluations:

1. Thermal-Hydraulic
2. Structural Integrity
3. Design Pressure Differential
4. Tube Integrity
5. Flow-Induced Tube Vibration and Tube Wear
6. Loose Parts
7. Tube Hardware
8. Steam Drum
9. Chemistry
10. RG 1.121
11. Supports

The Technical Evaluation included as part of this LR describes the input parameters, assumptions and acceptance criteria used to evaluate SG performance relative to the SPU.

A summary regarding the adequacy of the SGs and their supports under SPU conditions concludes this LR subsection.

MPS3 Current Licensing Basis

The generic CLB provided in Section 2.2.2 applies to the SG and its supports, with the following amplifications.

The SGs are vertical shell and U-tube evaporators with integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the SG. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. Steam is then passed through the moisture separator reheaters, turbine and the condenser. Condensate is returned to the SGs via the feed pumps and feedwater heaters. There are four SGs.

FSAR Section 5.4.2.1.1 states in part that all pressure boundary materials used in the SGs are selected and fabricated in accordance with the requirements of Section III of the ASME Code. FSAR Table 5.2-1 provides ASME B&PV Code Edition and Addenda applicable to the SGs. A general discussion of materials specifications is given in FSAR Section 5.2.3, with types of materials listed in FSAR Tables 5.2-2 and 5.2-3.

FSAR Section 5.4.2.1.1 states that SG tubes are fabricated from corrosion resistant Inconel 600 thermally treated, a nickel-chromium-iron alloy (ASME SB-163). The channel head divider plate is Inconel (ASME SB-168). The interior surface of the reactor coolant channel head, nozzles, and manways are clad with austenitic stainless steel.

FSAR Section 5.4.2.1.2 describes the SG tube support plates. “These plates are made of corrosion resistant stainless steel 405 alloy and incorporate a four-lobe hole design (quatrefoil) that provides greater flow area adjacent to the tube outer surface and eliminates the need for interstitial flow holes. The resulting increase in flow provides higher sweeping velocities at the tube/tube support plate intersections.”

FSAR Section 5.4.2.1.3 addresses the compatibility of SG tubing with the primary and secondary coolant. This section also addresses the compatibility of the tube support plates with the secondary water chemistry environment. Inconel 600 tubing is stated to have excellent resistance to general and pitting type corrosion. Also, increased margin against primary and secondary side cracking has been obtained by the use of thermally treated Inconel 600 tubing. The tube support plates used in the Model F are ferretic stainless steel, which has been shown in laboratory tests to be resistant to corrosion in the AVT environment.

SG design data is shown in FSAR Table 5.4-3. Code classifications for the SG components are provided in FSAR Section 3.2. Although the ASME classification for the secondary side is specified to be Class 2, the current philosophy is to design all pressure retaining parts of the SG, and thus both the primary and secondary pressure boundaries, to satisfy the criteria specified in Section III of the ASME Code for Class 1 components.

FSAR Section 5.4.2.5 describes the possibility of degradation of tubes due to either mechanical or flow-induced excitation. FSAR Section 5.4.2.5 states in part that the primary source of tube vibration is fluid turbulence, and the magnitude of the vibration is so small that when combined with its total random nature, its contribution to tube fatigue is negligible. Therefore, fatigue degradation due to flow-induced vibration is not anticipated.

The MPS3 SGs are inspected per the requirements of Section XI of the ASME B&PV Code, 1989 Edition, no addenda. The SG NDE program is described in FSAR Section 5.4.2.2 and summarized in FSAR Table 5.4-4.

FSAR Section 5.4.14.1.2 states in part that the supports for each SG consist of vertical, upper, and lower lateral supports.

Four individual column assemblies provide the vertical support for each SG. Each column assembly consists of a lower clevis, column, lug, extension tube, and upper column clevis. The upper clevises are bolted to the SG tube sheet and the lower clevises are anchored to the concrete floor. The four vertical column assemblies transmit vertical forces from the SG to the cubicle floor.

The lateral (upper and lower) supports are provided by eight double-acting hydraulic snubbers. Each lateral support has four hydraulic snubber assemblies which permit motion of the SG due to thermal expansion of the RCS. Vertical SG thermal motions are accommodated by the upper lateral support assembly. The hydraulic snubbers are designed to lock and resist dynamic forces which result from seismic and/or pipe rupture conditions.

The lower lateral support assemblies are bolted to the SG tube sheet and the concrete wall. The upper lateral support assemblies are bolted to the SG restraint ring and the concrete wall. SG supports are shown on the FSAR Figures 5.4-11 and 5.4-12.

FSAR Table 3.9N-1 summarizes RCS design transients, which apply to the SG, for normal, upset, emergency, faulted and test conditions. FSAR Chapter 15 addresses component responses to various limiting design transients in more detail.

The MPS3 SGs and supports were evaluated for continued acceptability regarding plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, documents the results of that review. NUREG-1838, Sections 2.3B.1.4 and 3.1B are applicable to the SGs. NUREG-1838 Sections 2.4B.3 and 3.5B are applicable to the SG supports.

2.2.2.5.2 Technical Evaluation

The technical evaluations of the 11 areas identified in Section 2.2.2.5.1 are discussed in Sections 2.2.2.5.2.1 through 2.2.2.5.2.11. Tables 2.2.2.5.2.1-1 through 2.2.2.5.2.10-2 summarize key inputs and analysis results.

2.2.2.5.2.1 Thermal-Hydraulic Evaluation

2.2.2.5.2.1.1 Introduction

Thermal-hydraulic analyses were performed to assure that the MPS3 SGs remain within acceptable bounds after the SPU. The key thermal-hydraulic factors of interest include: 1) potential for tube dryout, 2) hydrodynamic stability, 3) moisture carryover (MCO), 4) SG mass, 5) circulation ratio, 6) secondary side pressure drops and 7) average heat flux. MPS3 has four Model F SGs, each with sixteen 20 inch diameter moisture separators.

2.2.2.5.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The reference case for this evaluation was established as the current 100 percent power case (nominal 3425 MWt NSSS power; see Table 2.2.2.5.2.1-1).

The SPU NSSS design parameters are defined in Section 1.1, Table 1-1. Cases 1 through 6 were evaluated for 3666 MWt NSSS power.

Acceptance Criteria

The relevant acceptance criteria for MPS3 at SPU conditions are as follows:

- There is no local dryout on the tube wall.
- The damping factor for hydrodynamic instability evaluation is negative
- The projected MCO values for MPS3 stay below the erosion-corrosion threshold value of 0.5 percent.
- For the different uprated conditions considered, changes in the primary and secondary mass and heat content are small; 10 percent or less.
- No significant effect on sludge accumulation or local concentrations will occur.
- No adverse effect on feed system operation will occur.

2.2.2.5.2.1.3 Description of Analyses and Evaluations

Secondary side thermal-hydraulic characteristics were calculated at the SPU conditions. A three-dimensional flow field analysis for the secondary side of the SG was also performed to examine the potential for local tube wall dryout. Local dryout on the tube wall was also evaluated using the correlation for the departure from nucleate boiling (DNB), which could result in excessive build-up of tube scale.

Method Discussion

Steady state SG characteristics such as primary temperature, circulation ratio, steam flow rate, steam pressure, secondary side pressure drop, secondary fluid inventory and damping factor were calculated. The results were then used to evaluate acceptability at SPU conditions. The calculated operating conditions were utilized as input for evaluating margin-to-tube dryout and to estimate MCO for the various operating conditions. The following areas were evaluated:

Tube Dryout Potential

The potential for tube wall dryout is assessed by the DNB index (ratio of the calculated local mixture quality on the secondary side of the bundle to the predicted quality at the DNB transition). Local dryout at the tube wall is also called departure from nucleate boiling (DNB), which can result in excessive buildup of tube scale. An evaluation of the tube wall dryout potential was made for the SPU conditions.

Hydrodynamic Stability

The hydrodynamic stability of an SG is characterized by a damping factor. A negative value of this parameter indicates a stable unit. Therefore, the hydrodynamic stability value for the MPS3 SGs was calculated at the SPU conditions.

Moisture Carryover Evaluation

MCO may result in flow assisted corrosion (FAC) problems in the steam piping and/or steam turbine (See Section 2.1.8). Therefore, an MCO assessment was performed for the SPU conditions.

Prediction of Secondary Side Mixture Quality at DNB

The ratio of the local steam quality (X) to the quality at DNB (X_{DNB}) in every flow cell of the model was determined. The largest (X/X_{DNB}) value is expected for the operating conditions resulting in low values of circulation ratio, steam pressure and coolant temperature, which among the uprate conditions occurs in Case 2. It was, therefore, adequate to examine Case 2 only because this case has the highest potential for dryout. If this case is free of dryout, then all other cases are also free of dryout

Steam Generator Mass Change

Secondary-side mass tends downward with an increase in power. For the different uprated conditions considered for MPS3, the change in secondary-side water mass is assessed. A small change is judged to have no effect on the processes related to void in the tube bundle.

Circulation Ratio Change

The circulation ratio is a measure of the bundle flow in relation to the steam flow and is primarily a function of steam flow (power). The effect of SPU conditions on the potential for the accumulation of contaminants on the tubesheet and in the bundle is assessed below.

Secondary Side Pressure Drop Change

The total secondary side pressure drop (from the feedwater inlet nozzle to the steam outlet nozzle) at SPU conditions has been evaluated to assess the effect on feedwater system operation.

Average Heat Flux Change

The average heat flux in an SG is directly proportional to heat load and inversely proportional to heat transfer area in service. A measure of the margin for DNB transition or local tube wall dryout in the bundle is a check of the ratio of the local quality to the estimated quality at the DNB transition. The MPS3 Model F SG tube bundles are evaluated below for acceptable operation in the nucleate boiling regime at the SPU conditions.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the SG components are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. The changes associated with operating the SGs at SPU conditions do not adversely affect the reactor coolant pressure boundary integrity. Thus, no new aging management effects are identified and no new commitments are required for MPS3 for the SGs beyond those described in this report. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.1.4 Results

All calculated thermal-hydraulics parameters of the MPS3 are projected to be within acceptable ranges for operation at SPU conditions with tube plugging levels of up to 10 percent, with the exception of MCO at reduced inlet conditions.

The following is a summary of the results of the thermal hydraulic analysis of the MPS3 SGs at the analyzed SPU NSSS power level of 3666 MWt.

- **Tube Dryout Potential**

The DNB index increases with elevation in the tube bundle and it peaks in the U-bend with the hot side exhibiting a higher index than the cold side. The DNB index in the U-bend that shows the highest value is [ ] ^{a,c} at a small locality, versus the limit of unity. This demonstrates that the SGs have sufficient DNB margin for all analyzed conditions and, therefore, are not expected to experience local dryout on any tube wall.

- **Hydrodynamic Stability: Damping Factor**

The hydrodynamic stability of an SG is characterized by a damping factor. A negative value of this parameter indicates a stable unit. That is, small perturbations of thermal and hydraulic parameters (e.g., flow, pressure, or temperature) die out rather than grow in amplitude. The damping factor remains at a high negative value, varying from [ ]^{a,c} hr^{-1} to [ ]^{a,c} hr^{-1}, for all SPU conditions in Table 2.2.2.5.2.1-1. The SGs are expected to continue to operate in a hydrodynamically stable manner for all operating conditions after the SPU.

- **Moisture Carryover**

All the MCO values except for Case 1 and Case 2 remain below the design limit of 0.25 percent (Table 2.2.2.5.2.1-1). However, a higher MCO limit of 0.5 percent is acceptable as this is the threshold for erosion and corrosion (FAC) for the piping and valves downstream of the steam generators. The conditions defined in Case 1 and Case 2 are of limited duration and occur at the end of the cycle during coastdown, therefore, higher MCO than 0.25 percent is not a concern. Experience shows that measured MCO tends to be less than predicted.

- **SG Secondary Side Mass**

For the various SPU conditions considered, the secondary-side water mass may vary from [ ]^{a,c} percent to [ ]^{a,c} percent relative to the current full power conditions. A change of this magnitude has no effect on the processes related to the void in the bundle.

- **Circulation Ratio**

The circulation ratio is a measure of the bundle flow in relation to the steam flow. It is primarily a function of the steam flow (power). Results in Table 2.2.2.5.2.1-1 show that the circulation ratio may decrease by [ ]^{a,c} percent to [ ]^{a,c} percent at the SPU conditions. The bundle flow may decrease by [ ]^{a,c} percent to [ ]^{a,c} percent. The bundle flow is expected to be large enough to minimize accumulation of contaminants on the tubesheet and in the bundle. Therefore, no significant effect on sludge accumulation or local concentrations is expected. As discussed previously, the range of circulation ratio results in no local dryout.

- **SG Pressure Drop**

The total secondary-side pressure drop (from the feedwater nozzle inlet to steam nozzle outlet) after the SPU may increase by up to [ ]^{a,c} psi. This increase is small in relation to the total feed system pressure drop and has no significant effect on the feed system operation.

- **Average Heat Flux**

The average heat flux value increases with power and tube plugging. With the SPU, increased total heat load is passed through the same bundle heat transfer area, increasing heat flux in proportion to the power increase. However, this increase in heat flux is acceptable since it does not lead to tube dryout as previously discussed.

2.2.2.5.2.2 Structural Integrity Evaluation

2.2.2.5.2.2.1 Introduction

The structural integrity evaluation of the SG was performed for an SPU NSSS power level of 3666 MWt, and SG tube plugging (SGTP) over the range from 0 to 10 percent with a primary average temperature (T_{avg}) window from 571.5 °F to 589.5 °F, a full load SG outlet pressure ranging from 797 to 962 psia, and a feedwater temperature window from 390°F to 445.3 °F. The stresses, stress intensity ranges, and fatigue usage factors in the SG for the SPU range of conditions were determined by reconciling the original design basis analyses against the new SPU conditions provided in the design parameters in Section 1.1 and NSSS design transients in Section 2.2.6.

Acceptance of the results for SPU conditions was based on demonstrating continued compliance with the structural criteria in the ASME B&PV Code Section III, Subsection NB (Reference 1). These acceptance criteria are the same as those used for the original design basis analyses of the SGs.

The internal components, which are not part of the pressure boundary, are not governed by the ASME B&PV Code. However, ASME Code, Section III, Subsections NB and NF were adopted as guidelines for performing the structural analysis of these components (Reference 1).

The scope of the reconciliation was the entire SG pressure boundary, internal and external pressure boundary attachments, and all internal components. Formal reconciliations were performed for the divider plate, tubesheet and shell junction, tube-to-tubesheet weld, tubes, feedwater nozzle, secondary manway bolts, steam nozzle, secondary-side wrapper support system components, blowdown pipe, and channel head and stub barrel digital metal impact monitoring system (DMIMS) holes.

2.2.2.5.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The structural evaluation was performed for an SPU NSSS power level of 3666 MWt, SG tube plugging (SGTP) over the range from 0 to 10 percent, with a primary average temperature (T_{avg}) window from 571.5 °F to 589.5 °F, a full-load SG outlet pressure ranging from 797 to 962 psia, and a feedwater temperature window from 390 °F to 443.5 °F. The design parameters and transients for the SPU conditions are provided in Section 1.1 and Section 2.2.6.

Assumptions

The stresses, stress intensity ranges, and fatigue usage factors in the SGs for operation at the SPU conditions were calculated by reconciling the original design basis analyses. To quantify the change in the range of stress occurring during each postulated transient for the SPU relative to the design basis, an approximation method was used to determine the ratios between the pressure and temperature variations and prorating the range of stresses by these ratios. A detailed comparison was performed between the SPU and design basis transients to determine these temperature and pressure variation ratios. Variations were compared for the primary side inlet and outlet temperatures, secondary side temperatures, feedwater temperatures, primary side pressures, and secondary side pressures. The bounding ratios were used to prorate the stress results.

For simplicity, all components, except for the manway bolts on the pressure boundary bolted openings, were considered to operate at the SPU conditions for the full 60-year design life (Reference 2). Where this assumption was overly conservative, the original design basis transients were considered for 22 years of operation and the SPU transients for the remaining 38 years. Reductions in the fatigue life due to the SPU were considered for the pressure boundary manway bolts.

The original design basis external nozzle and attachment loads were used in the reconciliation analyses. No revisions were specified for the burst pipe loads with the exception of tube rarefaction loads for operation at the SPU conditions. The original design basis loads and revised tube rarefaction loads were used in the reconciliation analyses. The seismic loading of the internals was unaffected by the SPU and the original design basis loads remain bounding. The bolt preloads for bolted pressure boundary openings were established on the basis of "leak proofing" the joints. The original design basis preloads were used in the reconciliation analyses.

The design basis analysis demonstrating protection against non-ductile fracture is unaffected by the SPU since the lower temperature operation steam pressure remained unchanged. Only pressures at less limiting elevated temperatures were changed. As a result, the current reconciliation of the design basis analysis remains bounding for the SPU conditions.

Acceptance Criteria

Continued compliance with the current SG design basis analysis is the acceptance criteria for the structural analysis for SPU conditions. For the structural evaluation of the pressure boundary components, the acceptance criteria from ASME, Section III, Subsection NB for Class 1 components continued to remain applicable (Reference 1). Excessive plastic deformation is prevented by limits on the acceptable primary stresses. Plastic instability and incremental collapse are prevented by limits on the acceptable primary-plus-secondary stresses. High-strain, low-cycle fatigue is prevented by limits on the total stresses and their cycles. Satisfaction of these limits demonstrates continued compliance with the current design acceptance criteria and, therefore, the adequacy of the SG design for operation at the SPU conditions for the remainder of the 60-year design life.

The SG internal components, other than the U-tubes, are not part of the pressure boundary and, therefore, are not governed by the ASME Code. However, ASME Code Section III Subsections NB and NF were adopted as guidelines for performing the structural analysis of these components (Reference 1). These components were reviewed and it was determined that they satisfy the ASME Code requirements for components not requiring an analysis for cyclic operation. As a result, a fatigue analysis was not performed for the internals. The feedwater ring was analyzed for fatigue since it is the most highly loaded of all the internals due to rapid feedwater flow and temperature changes.

2.2.2.5.2.2.3 Description of Analyses and Evaluations

From a structural standpoint, the increased pressure and temperature variations specified in the design parameters in Section 1.1 and design transients in Section 2.2.6 during SPU normal and upset operating conditions impact the SG. Both the primary and secondary side SG components are affected to differing degrees by these increased pressure and temperature variations, resulting in increased stress intensity ranges and fatigue usage factors. The SG ASME code design conditions are unaffected by the SPU conditions except for those components affected by primary-to-secondary-side pressure differentials.

The SG SPU structural evaluation was performed by reconciling the existing SG design basis analyses relative to the conditions specified in the design parameters in Section 1.1 and design transients in Section 2.2.6. The scope of the reconciliation included all of the SG pressure boundary and the internal components. Formal reconciliations were performed for the divider plate, tubesheet and shell junction, tube-to-tubesheet weld, tubes, feedwater nozzle, secondary manway bolts, steam nozzle, secondary-side wrapper support systems components, blowdown pipe and channel head and stud barrel digital metal impact monitoring system (DMIMS) holes.

Both high and low T_{avg} operations were considered in the reconciliation. High T_{avg} operation corresponded to primary-and-secondary-side operating temperatures of 589.5 °F and 537.4 °F, respectively. Low T_{avg} operation corresponded to primary- and-secondary-side operating temperatures of 571.5 °F and 517.8 °F, respectively. The more bounding of the conditions was considered, and depended on the location of the component.

All components, except for the pressure boundary bolted opening manway bolts, were considered to operate at the SPU conditions for the 60-year life (Reference 2). If this assumption was too conservative, the current operating condition based design basis transients were considered for 22 years of operation, and the SPU condition based transients were considered for the remaining 38 years. A reduction in the fatigue life associated with the SPU conditions was necessary only for the manway bolts.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the SG components are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. The changes associated with operating the SGs at SPU conditions do not adversely affect the reactor coolant pressure boundary integrity. Thus, no new aging management effects are identified and no new commitments are required for MPS3 for the SGs beyond those described in this report. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.2.4 Results

The results of the evaluation demonstrated that the SG pressure boundary and internal components continue to comply with the structural criteria of the ASME Code Section III, Subsection NB and NF for operation at the SPU conditions (Reference 1), with the exception of the SG secondary side manway bolts.

The SPU associated changes in operating conditions requires the following:

- The secondary manway bolts will need to be replaced after 30 years of equivalent design cycles of actual operation rather than 20 years for the current non-SPU condition operation. This change is a result of the plant life extension to 60 years of operation with no change to the number of transient cycles. Secondary manway bolts are acceptable for SPU conditions.

Tables 2.2.2.5.2.2-1 and 2.2.2.5.2.2-2 list the stresses, stress intensities (SI) and fatigue usage factors for both pre-SPU conditions and SPU conditions. For design conditions, only the primary-to-secondary-side pressure differential is affected by the SPU. The internals are largely unaffected by the SPU and are not included in Tables 2.2.2.5.2.2-1 and 2.2.2.5.2.2-2.

2.2.2.5.2.2.5 References

1. ASME Boiler and Pressure Vessel Code Section III, Rules for Construction of Nuclear Vessels, 1971 Edition, Summer 1973 Addenda, American Society of Mechanical Engineers, New York, New York.

2. NUREG-1838, Docket Nos. 50-336 and 50-423, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, October 2005.

2.2.2.5.2.3 Design Pressure Differential

2.2.2.5.2.3.1 Introduction

An analysis was performed to determine if the ASME B&PV Code, 1971 Edition plus Addenda through Summer 1973 limits on design primary-to-secondary pressure differential drop (ΔP) are satisfied for the applicable transient conditions for the MPS3 SPU (Reference 1).

2.2.2.5.2.3.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The design pressure limit for primary-to-secondary pressure differential is [ ]^{a,c} psi as defined in the applicable design specification.

Acceptance Criteria

In accordance with Reference 1, the primary-to-secondary differential pressure for the normal/upset transient conditions is subject to the following design pressure requirements:

- Normal condition transients: Primary-to-secondary pressure gradient shall be less than the design limit of [ ]^{a,c} psi.

- Upset condition transients: If the pressure during an upset transient exceeds the design pressure limit, the stress limits corresponding to design conditions apply using an allowable stress intensity value of 110 percent of those defined for design conditions. In other words, as long as the upset condition pressure values are less than 110 percent of the design pressure values, no additional analysis is necessary. For the MPS3 SGs, 110 percent of the design pressure differential limit corresponds to [ ]^{a,c} psi.

2.2.2.5.2.3.3 Description of Analyses and Evaluations

The primary-to-secondary design pressure differential evaluation was based on the NSSS design transient parameters given in Section 2.2.6. Two sets of transient parameters are defined, one corresponding to a high T_{avg} mode of operation, and one corresponding to a low T_{avg} mode of operation. In addition, transient parameters are defined for two different tube plugging levels, 0 percent and 10 percent. The pressure differentials across the primary-to-secondary-side pressure boundary are calculated for the high T_{avg} and low T_{avg} full-power conditions corresponding to the 10 percent tube plugging level which bound the 0 percent tube plugging condition (Table 2.2.2.5.2.3-1). The corresponding full-power conditions are given in Section 1.1.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the SG components are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. The changes associated with operating the SGs at SPU conditions do not adversely affect the reactor coolant pressure boundary integrity. Thus, no new aging management effects are identified and no new commitments are required for MPS3 for the SGs beyond those described in this report. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.3.4 Results

The results of the analyses performed for the primary-to-secondary-side pressure differential for MPS3 are all below the applicable design pressure limits of [ ]^{a,c} psi and [ ]^{a,c} psi for normal and upset conditions, respectively.

2.2.2.5.2.3.5 References

1. ASME Boiler and Pressure Vessel Code, Section III, Rules for Construction of Nuclear Vessels, 1971 Edition, Summer 1973 Addenda, American Society of Mechanical Engineers, New York, New York.

2.2.2.5.2.4 Tube Integrity

2.2.2.5.2.4.1 Introduction

SG tubing integrity concerns arising as a result of the MPS3 SPU were evaluated. Over a period of time, some tubes may become degraded locally under the influence of the operating loads and chemical environment in the SG. The SG tube integrity effects of the SPU depend upon changes in the potential initiation and propagation rates for stress corrosion cracking (SCC) and in the structural capability.

2.2.2.5.2.4.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The SPU NSSS design parameters in Section 1.1 list the reactor vessel outlet temperature as 615°F; the current best estimate average vessel outlet temperature (T_{hot}) is 615.5°F, associated with the current T_{avg} value of 587°F. This value is lower than the prevailing T_{hot} value for plants with Model F SGs (618°F) in the more recent Power Capability Working Group Documents. Uprate parameters provided in Section 1.1 list vessel outlet temperature (T_{hot}) as a minimum of 605.6°F and as maximum of 622.6°F; the best estimate average T_{hot} value expected after the SPU uprate is 617.2°F based on an expected plant T_{avg} = 587°F. The best estimate average T_{hot} value is 619.7°F corresponding to T_{avg} = 589.5°F. In the event of a negative change in operating T_{hot} from 617.2°F, there would be no exacerbation of tube degradation mechanisms potentially operative in the MPS3 SGs, but the increased pressure differential would have an impact on allowable degradation, i.e., condition monitoring limits.

Acceptance Criteria

SG tube integrity shall remain consistent with the performance criteria of NEI 97-06, Rev. 2, "Steam Generator Program Guidelines" (Reference 1) at SPU conditions.

2.2.2.5.2.4.3 Description of Analyses and Evaluations

The potential for the occurrence of localized tube wall degradation in the MPS3 SGs at the SPU conditions has been evaluated and the results are summarized below.

Potential Tube Degradation Mechanisms

As presented in the MPS3 RF10 CMOA (Reference 1), the potential tube degradation mechanisms are:

- Wear at anti-vibration bars (AVB)
- Wear tube at flow distribution baffle (FDB)
- Wear resulting from foreign objects
- Pitting at secondary side sludge/deposits
- OD IGA/SCC (IGA = Intergranular Attack) within hot leg expansion transitions, Secondary sludge deposits, Row 1 and 2 U-bends, Dents, Tube support intersections, Tube freespan sections
- PWSCC within hot leg expansion transitions, expansion anomalies, Row 1 and 2 U-bends, Welded I-600 plugs.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the SG components are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. The changes associated with operating the SGs at SPU conditions do not adversely affect the reactor coolant pressure boundary integrity. Thus, no new aging management effects are identified and no new commitments are required for MPS3 for the SGs beyond those described in this report. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.4.4 Results

On the basis of temperature increase alone, the mechanical wear processes are unlikely to be significantly changed. The prospects for increased pitting are low in the absence of deterioration in the secondary chemistry environment, a circumstance not related to the SPU uprate. The overall impact of the SPU may be characterized more appropriately as an enhancement of statistical and thermodynamic properties applicable to a material (Alloy 600TT) susceptible to SCC under the appropriate combination of temperature, stress, and environment.

For the expected best estimate difference, T_{hot} increasing from 615.5°F to 617.2°F, the 1.7°F increase yields a ratio of the corrosion rates determined from the Arrhenius equation equal to 1.07 for PWSCC; this predicts a 7 percent potential increase in the rate of PWSCC initiation at the higher temperature. For ODSCC, the energy of activation is approximately 32 Kcal/mol; the increase in rate at which cracking could initiate relative to present conditions is estimated to be about 4.4 percent for the 1.7°F best estimate increase. If the higher T_{avg} (589.5°F) were to be realized, the potential increase in T_{hot} would be 4.2°F; the corresponding projected rates of increase for initiation of PWSCC and ODSCC would be 18 percent and 11 percent.

Based on the above, it is concluded that the performance criteria of NEI 97-06, Rev. 2 will continue to be met at the SPU conditions through the completion of degradation, condition monitoring and operational assessments.

2.2.2.5.2.4.5 References

1. NEI 97-06, Rev. 2, Steam Generator Program Guidelines, May 2005.

2. M3-EV-05-0032, Rev. 0, Millstone Unit 3 Steam Generator Condition Monitoring and Operational Assessment Report Refueling Outage 10, January 18, 2006.

2.2.2.5.2.5 Flow-Induced Vibration and Tube Wear

2.2.2.5.2.5.1 Introduction

The impact of the SPU for MPS3 on SG tube wear was evaluated based on the current design basis analysis and includes the changes in the thermal-hydraulic characteristics of the secondary side of the SG resulting from the SPU. The effects of these changes on the fluid-elastic stability ratio and amplitudes of tube vibration due to turbulences have been addressed. In addition, the effects of the SPU on potential future tube wear have also been considered.

2.2.2.5.2.5.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

Previously established values of fluid-elastic stability, turbulent amplitude of vibration and tube wear were updated to incorporate the new operating parameters from Section 1.1.

Acceptance Criteria

SG tube integrity shall remain consistent with the performance criteria of NEI 97-06, Rev. 2, "Steam Generator Program Guidelines" (Reference 1) at SPU conditions.

2.2.2.5.2.5.3 Description of Analyses and Evaluations

The results from the original vibration and wear analysis were modified to account for changes in the secondary-side operating conditions associated with the most limiting of the SPU conditions. The previously established values of fluid-elastic instability, turbulent amplitudes of vibration, and tube wear were modified to incorporate the new operating parameters from Section 1.1. The fluid-elastic excitation and turbulence of flow were analyzed by using the finite element dynamic computer code, FLOVIB in the original design basis analysis. Although higher damping values are expected based on information in open literature, 1 percent damping was used for the tubes in the original design basis analysis for conservatism. The following types of localized tube degradation are concluded not to be impacted by loads other than pressure.

- Axial Degradation anywhere in the tube bundle.
- Circumferential degradation in the U-bend flank region
- Circumferential degradation less than 270^{o} in recirculating SGs in straight sections below the top of the tubesheet
- Circumferential degradation in recirculating SGs less than 25 percent degraded area
- Flat bar wear in recirculating SGs

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the SG components are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. The changes associated with operating the SGs at SPU conditions do not adversely affect the reactor coolant pressure boundary integrity. Thus, no new aging management effects are identified and no new commitments are required for MPS3 for the SGs beyond those described in this report. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.5.4 Results

The analysis of the MPS3 Model F SGs indicates that significant levels of tube vibration do not occur from either the fluid-elastic, vortex shedding or turbulent mechanisms as a result of the SPU conditions. In addition, the projected level of tube wear as a result of vibration remains small and does not result in unacceptable wear for the general population of tubes and for those tubes exhibiting wear following eddy current testing.

The analysis indicates that as a result of the proposed uprate, significant levels of tube vibration will not occur from either the fluid-elastic or turbulent mechanisms above those associated with the non-uprated condition. Results show that the increase in fluid-elastic stability could increase by as much as 22.3 percent while the turbulence would increase by as much as 49.6 percent for the uprate to 3666 MWt NSSS power. This results in a maximum stability ratio of 0.612 (< than the allowable of 1.0) and maximum turbulence induced amplitude of 2 mils, (less than 1/2 the distance separating the tubes). Both conditions remain acceptable following the uprate.

The maximum pre-uprate predicted wear for the tubes is 0.0032 inch over the 40 year design life of the SGs. The uprate to 3666 MWt NSSS power increases the tube wear by 49.6 percent, over what is calculated for the original design power level. The maximum post-uprate wear over 60 years is less than 8 mils. This amount of wear will not significantly affect the tube integrity, and is judged to be acceptable. Therefore, the proposed uprate is not projected to result in an unacceptable rate of tube wear.

Fatigue usage associated with general flow-induced vibration (FIV) resulting from the most limiting uprated operating condition indicates that for operation in the uprated condition, the corresponding maximum stress levels would be less than 0.2 ksi. This level of stress remains well below the endurance limit of ~20 ksi @ 1E11 cycles. Hence, the fatigue usage factor associated with the FIV induced tube loadings in the uprated operating condition is 0.0.

Addressing high cycle fatigue in the tubes has also been performed. This condition is a result of various factors including a build-up of corrosion products associated with drilled holes in carbon steel tube support plates (TSPs). Since the stainless steel support plates used in the MPS3 SG are designed to inhibit the introduction of corrosion products, the support condition (i.e., denting) necessary for the development of high cycle fatigue cannot occur. As a result, high cycle fatigue associated with unsupported inner row tubes cannot occur in this model of SG and is not a concern.

In summary, these calculations indicate that operation at the projected uprated conditions will not result in rapid rates of tube wear or high levels of tube vibration to the general population of the tubes. Wear, already experienced, will increase insignificantly as a result of the uprate. Monitoring the wear through eddy current inspections during outages will provide the basis for the remediation of the effects of tubes already experiencing wear and will provide the basis to stabilize and/or plug tubes that exhibit wear in excess of technical specification limits.

The results are summarized in Table 2.2.2.5.2.5-1.

2.2.2.5.2.5.5 References

1. NEI 97-06, Rev. 2, Steam Generator Program Guidelines¸ May 2005.

2.2.2.5.2.6 Loose Parts

2.2.2.5.2.6.1 Introduction

Loose parts have been detected in all four SGs over the history of MPS3. Detection has been accomplished via examinations required by Technical Specifications and NEI 97-06. Reasonable effort has been spent to remove all identified loose parts upon discovery. Those remaining in the SGs are documented, analyzed for future impact on SG tubes, and affected tubes are plugged and stabilized per the Steam Generator Program. Affected tubes remaining in service are monitored during subsequent examinations.

For SPU conditions, an analysis was performed to determine if the modified operating conditions would affect the previously calculated wear-time analysis on the secondary side and the impact on the primary side due to loose parts located on the primary side.

2.2.2.5.2.6.2 Input Parameters, Assumptions and Acceptance Criteria:

Input Parameters and Assumptions

The current analysis considers:

- Previous loose part wear experience.
- Secondary side thermal-hydraulic conditions for each of the SPU conditions (Section 1.1).
- Previously evaluated loose parts on the primary side.

Major assumptions in the current analysis include:

- A pre-existing wear scar of [ ]^{a,c} percent wear depth is present on the tubes. Normal tube eddy current inspections verify that this conservative value is not exceeded.
- The SGs are operating at SPU conditions (Section 1.1).

Acceptance criteria

SG tube integrity shall remain consistent with the performance criteria of NEI 97-06, Rev. 2, "Steam Generator Program Guidelines" (Reference 1) at SPU conditions.

2.2.2.5.2.6.3 Description of Analyses and Evaluation

Secondary Side Loose Part Analysis

With certain changes in SG operating conditions such as power level, feedwater temperature, steam pressure or plugging level, there could be a corresponding change in the thermal-hydraulic characteristics relevant to loose part induced tube wear. Calculations were performed in the original loose part analyses to identify secondary- side flow characteristics that could influence tube vibration and corresponding loose part wear. Loose part wear is a function of drag force and tube displacement. Since both drag force and displacements are a function of density and velocity, a comparison was made between the square of the density times velocity squared for each of the proposed uprate conditions (Table 2.2.2.5.2.6-1). In all cases the SPU conditions are less severe than the originally evaluated condition since all ratios are less than 1.0. Therefore, the original evaluation bounds the SPU conditions.

Primary Side Loose Part Analysis

The primary side velocity was calculated for power uprate conditions and was found to be less than the velocity used in the original analysis. Therefore, the primary side loose part analysis under SPU is bounded by the original evaluation.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the SG components are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. The changes associated with operating the SGs at SPU conditions do not adversely affect the reactor coolant pressure boundary integrity. Thus, no new aging management effects are identified and no new commitments are required for MPS3 for the SGs beyond those described in this report. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.6.4 Results

For the Secondary Side loose parts analysis, Condition Monitoring and Operational Assessments (CMOA) have consistently documented past and future conformance of the Steam Generators to the performance criteria of NEI 97-06. As noted in the analysis above, the changes in flow characteristics are bounded by previous analysis, thus continued conformance to the performance criteria is expected.

For the primary side loose parts analysis, the previous calculations envelop the SPU conditions. Therefore, it is conservative to use the previous evaluation to address the SPU conditions as well.

The loose object(s) will be evaluated on a cycle-to-cycle basis to determine the acceptability of future operation.

2.2.2.5.2.6.5 References

1. NEI 97-06, Rev. 2, Steam Generator Program Guidelines, May 2005.

2.2.2.5.2.7 Tube Hardware

2.2.2.5.2.7.1 Introduction

Mechanical repair hardware refers to components such as plugs and stabilizers that are installed in SG tubes to address tube degradation. These components were re-analyzed for the operating conditions in Section 1.1 and NSSS transients in Section 2.2.6 associated with the SPU.

2.2.2.5.2.7.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

Plant operating parameters at 3666 MWt NSSS power are used to evaluate the tube stabilizers and plugs (Section 1.1).

The critical parameter affecting the design of the plugs is the primary-to-secondary differential pressure in the steam generator. The current design differential pressure was shown to bound the normal/upset conditions for the SPU. Plug integrity was also evaluated at primary hydrostatic and secondary hydrostatic test pressures.

Acceptance Criteria

Mechanical and Weld Plugs

The SG hardware primary stresses due to design, normal, upset, emergency, faulted and test conditions must remain within the allowable values of Reference 1. In addition to the stress criteria, retention of the mechanical and weld plug must be ensured.

Stabilizers

Stabilized tubes do not result in deleterious contact with adjacent tubes.

2.2.2.5.2.7.3 Description of Analyses and Evaluations

Mechanical Ribbed and Rolled Plugs

The enveloping condition for the mechanical plugs is the one that results in the largest pressure differential between the primary and secondary side of the SG. Both the uprate parameter changes in Section 1.1 and the NSSS design transients in Section 2.2.6 were considered in determining the effect of the SPU on the mechanical plugs. The mechanical and rolled plug analyses at SPU are based upon structural analysis of the plugs performed in accordance with Reference 1.

Weld Plugs

Shop weld plugs and the field weld plug were evaluated for the SPU conditions. Structural analyses were performed on the shop weld tube plugs and the field weld plug for the SPU conditions. The analyses were performed to the applicable requirements of Reference 1. The analyses for both types of weld plugs addressed design, normal/upset, emergency, faulted and test conditions. Fatigue calculations were also performed.

Bare-Cable Stabilizer Qualification

The qualification method employed shows that the stabilizers function to retain severed tubes, to dampen vibration, to mitigate wear on the plugged tube, and to prevent loose parts from severing a tube are met. The dynamic characteristics of a stabilized SG tube are considered for flow-induced vibration to show that these design objectives are met.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the SG components are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. The changes associated with operating the SGs at SPU conditions do not adversely affect the reactor coolant pressure boundary integrity. Thus, no new aging management effects are identified and no new commitments are required for MPS3 for the SGs beyond those described in this report. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.7.4 Results

Mechanical Ribbed Plugs

Results of the analyses performed for the mechanical plugs show that the mechanical plug design satisfy all applicable stress and retention acceptance criteria at the SPU conditions.

Mechanical Rolled Plugs

The mechanical rolled plugs were analyzed for the SPU conditions. The mechanical rolled plugs were determined to be acceptable for the SPU.

Weld Plugs

The welded plugs were evaluated for SPU conditions and determined to be acceptable.

Bare-Cable Stabilizer Qualification

The evaluation of the bare-cable stabilizers showed the stabilizer installations are acceptable for SPU conditions. It was also determined that potentially deleterious contact of the stabilized tube with adjacent active tubes could not occur.

Summary

It is concluded that the SG tube hardware components meet the stress/fatigue analysis requirements of the ASME Code, Section III for plant operation to support the MPS3 SPU.

2.2.2.5.2.7.5 References

1. ASME Boiler and Pressure Vessel Code, Section III, Rules for Construction of Nuclear Vessels, 1971 Edition, Summer 1973 Addenda, American Society of Mechanical Engineers, New York, New York.

2.2.2.5.2.8 Steam Drum

2.2.2.5.2.8.1 Introduction

An evaluation was performed to assess potential material loss through erosion-corrosion of the existing carbon steel feedwater ring and on adjacent steam drum components due to J-nozzle effluent discharge from increased feedwater flow rates due to the SPU.

2.2.2.5.2.8.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The assessment of the performance of the steam drum components considered plant thermal-hydraulic inputs in the Model F SGs during normal and uprated plant operating conditions.

All MPS3-specific field inspection data considered in this assessment of the performance of the steam drum components in the Model F SGs are based upon References 1 through 7.

Steam drum component field inspection data from other operating plants with identical or similar model Westinghouse SGs were also considered in this assessment.

Assumptions

The condition of the steam drum components, and in particular the feedwater ring, as reported via References 1 through 7 for the MPS3 Model F SGs is still valid.

Acceptance Criteria

The relevant acceptance criteria used as the basis for the evaluation performed are as follows:

- Degradation, if found to exist in any steam drum component, will not adversely impact or compromise the thermal performance or moisture separation function of the affected component.
- Degradation, if found to exist in any steam drum component, will not adversely impact or compromise the structural integrity of the component.
- Degradation, if found to exist in any steam drum component, will not create a loose part that will adversely impact or compromise the safe operation of the plant.

2.2.2.5.2.8.3 Description of Analyses and Evaluations

This evaluation of the impact of increased feedwater flow at SPU conditions is based upon examining past inspection results of the steam drum components of the MPS3 Model F SGs. These inspections within the MPS3 SGs have largely concentrated on the feedwater rings. Therefore, the evaluations have been divided into an evaluation of the feedwater rings based upon MPS3-specific inspection data and an evaluation of the remaining steam drum components within the MPS3 SGs. The evaluation on the remaining components is based upon visual inspections performed within the steam drums of identical or similar SGs.

Field inspection data of the feedwater rings in all four SGs at MPS3 was used to establish the current conditions.

Field inspection data of the steam drum components was used to establish industry experience on steam drum component degradation known to Westinghouse as of the issuance of this LR.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the SG components are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. The changes associated with operating the SGs at SPU conditions do not adversely affect the reactor coolant pressure boundary integrity. Thus, no new aging management effects are identified and no new commitments are required for MPS3 for the SGs beyond those described in this report. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.8.4 Results

Engineering Assessment of MPS3 Inspection Results Compared to Industry Experience

Using the acceptance criteria provided above as the basis for comparison, the following assessment can be made of the existing (as of 2006) conditions of the steam drum components of the MPS3 SGs relative to known industry conditions of the same components.

As of this writing, there has been no industry operational event (OE) issued that states that steam drum components will degrade following power uprates.

MPS3 Inspection Results Relative to Acceptance Criteria

Thermal-Hydraulic Concerns

Degradation, if found to exist in any steam drum component, will not adversely impact or compromise the thermal performance or moisture separation function of the affected component.

Feedwater Rings

The degradation noted through visual inspections and UT thickness measurements of the feedwater rings in the MPS3 SGs is generally more severe to known conditions in SGs of identical design (i.e., Model F SGs) as well as to similar designs (e.g., Model 51F SGs).

Although the erosion-corrosion process is ongoing and minimum thickness ligaments were identified (References 1 through 7), weld repairs were performed such that no through-wall holes were present in any of the four feedwater rings. Due to these feedwater ring to J-nozzle weld repairs, the resulting wall thicknesses will maintain the thermal-hydraulic conditions of the feedwater ring within the originally specified design requirements. Accordingly, the thermal performance of the SG steam drum region should also be maintained within the originally specified designed conditions. Therefore, from the thermal-hydraulic point of view, if additional material loss within the feedwater ring is detected under normal plant operation conditions, additional weld repairs would be performed. In addition, it is important to note that with increased feedwater flow expected during uprated plant operating conditions, material loss of the feedwater ring carbon steel base metal in areas already proven to be susceptible to erosion-corrosion (tees and reducers) may be accelerated. Continued monitoring by visual and UT thickness measurements is recommended at intervals to be determined and future weld repairs and/or partial or whole component replacement may become necessary to meet and maintain thermal-hydraulic performance requirements.

Other Steam Drum Components

All inspected steam drum components (other than the aforementioned feedwater rings) were found to be intact. There were no indications of anomalous conditions other than early evidence of very minor erosion-corrosion on the OD surface of a few primary separators. In addition, it can be stated that indications of significant levels of erosion-corrosion, missing material, deformed metal, excessive sludge/magnetite deposits, foreign objects, or worn material were not observed during any of the inspections.

Industry experience discussed above on identical primary separator structures in other plants does indicate that these structures are susceptible to erosion-corrosion degradation under non-uprated plant operating conditions. In the nominal case, the degradation reported in these other plants identified reduction in material thicknesses on the order of 25 percent of the original wall. A worst-case scenario would be through-wall holes in these structures.

Using this data as a guide, the potential exists that these same structures in the MPS3 Model F SGs may experience similar degradation. If the primary separators experience similar degradation as recently found to exist in other plants, it is judged that even with a reduced wall thickness, the primary separators would still maintain the thermal-hydraulic conditions within the originally specified designed requirements. Therefore, the thermal performance and moisture separation function of the SG should also be maintained within the originally specified designed conditions.

With the increased flow conditions within the steam drum expected from the SPU, the potential for material loss in the carbon steel primary separators may increase and even be accelerated. It is, therefore, recommended that continued monitoring of the primary separator structures by visual examination and UT measurements (as appropriate) be performed at intervals to be determined.

Structural Adequacy

Degradation, if found to exist in any steam drum component, will not adversely impact or compromise the structural integrity of the component.

Feedwater Rings

The degradation noted through visual inspections and UT thickness measurements reported in References 1 through 7 of the feedwater rings in the MPS3 SGs is generally more severe to known conditions in SGs of identical design (i.e., Model F SGs) as well as to similar designs (e.g., Model 51F SGs).

Although the erosion-corrosion process is ongoing and minimum thickness ligaments were identified (References 1 through 7), weld repairs were performed such that no through-wall holes were present in any of the four feedwater rings. Due to these feedwater ring to J-nozzle weld repairs, it is expected that any operational loads imposed upon the feedwater ring and weld repaired areas, considering further erosion-corrosion potential in the near-term, will not adversely impact or compromise structural integrity of the feedwater ring.

However, with increased feedwater flow expected during uprated plant operating conditions, material loss of the feedwater ring carbon steel base metal in areas already proven to be susceptible to erosion-corrosion (tees and reducers) may be accelerated. Continued monitoring by visual and UT thickness measurements is recommended at intervals to be determined. Future weld repairs and/or partial or whole component replacement may become necessary to meet and maintain structural integrity of the feedwater ring at uprated operating conditions.

Other Steam Drum Components

All inspected steam drum components (other than the aforementioned feedwater rings) were found to be intact. There were no indications of anomalous conditions other than early evidence of very minor erosion-corrosion on the OD surface of a few primary separators. In addition, it can be stated that indications of significant levels of erosion-corrosion, missing material, deformed metal, excessive sludge/magnetite deposits, foreign objects, or worn material were not observed during any of the inspections.

Industry experience discussed above on identical primary separator structures in other plants does indicate that these structures are susceptible to erosion-corrosion degradation under non-uprated plant operating conditions. In the nominal case, the degradation reported in these other plants identified reduction in material thicknesses on the order of 25 percent of the original wall. A worst-case scenario would be through-wall holes in these structures.

Using this data as a guide, the potential exists that these same structures in the MPS3 Model F SGs may experience similar degradation. Therefore, if degradation does exist in a manner similar to that experience in other plants, such degradation will have a negligible impact upon the structural adequacy of the steam drum components affected. Most material loss observed in other plants thus far has been in specific localized areas that do not have significant applied loadings (e.g., tangential nozzles). The amount of observed material loss in these other plants is not currently considered to be significant with respect to the major load conditions: steamline break (SLB) and seismic. Prior analysis performed for SGs with more significant erosion indicate that large margins are typically present for erosion of this type when occurring at these specific locations. As a result of the observed levels of material loss and prior analysis performed for other model SGs, it is expected that any operational loads imposed upon these components considering further erosion potential will not adversely impact or compromise their structural integrity.

With the increased flow conditions within the steam drum expected from the SPU, the potential for material loss in the carbon steel primary separators may increase and even be accelerated. It is, therefore, recommended that continued monitoring of the primary separator structures by visual examination and UT measurements (as appropriate) be performed at intervals to be determined.

Loose Parts

Degradation, if found to exist in any steam drum component, will not create a loose part that will adversely impact or compromise the safe operation of the plant.

Feedwater Rings

The degradation noted through visual inspections and UT thickness measurements reported in References 1 through 7 of the feedwater rings in the MPS3 SGs is generally more severe to known conditions in SGs of identical design (i.e., Model F SGs) as well as to similar designs (e.g., Model 51F SGs).

Although the erosion-corrosion process is ongoing and minimum thickness ligaments were identified (References 1 through 7), weld repairs were performed such that no through-wall holes were present in any of the four feedwater rings. Even in the extremely unlikely event that additional degradation would occur on an accelerated basis and result in a J-nozzle separating from the feedwater ring and becoming a loose part, the size of the J-nozzle and its attachment fillet weld of Inconel would limit its migration. The J-nozzle/attachment weld assembly would be expected to stay intact due to the inherit resistance of Inconel to erosion-corrosion. Note that a J-nozzle is capable of fitting through the shell ID and tube bundle wrapper OD annulus and migrating to the tubesheet, which occurred in one of the MPS3 SGs during J-nozzle replacement prior to commercial operation. However, this J-nozzle was a new J-nozzle that possessed no weld attachment. If a J-nozzle were to become a loose part due to erosion-corrosion, the size of the J-nozzle and its attachment fillet weld would limit its migration and prevent it from traveling down the shell ID and tube bundle wrapper OD annulus and contacting a tube. Hence, there is no potential for impact on tube integrity by a detached J-nozzle due to erosion-corrosion.

Other Steam Drum Components

All inspected steam drum components (other than the aforementioned feedwater rings) were found to be intact. There were no indications of anomalous conditions other than early evidence of very minor erosion-corrosion on the OD surface of a few primary separators. In addition, it can be stated that indications of significant levels of erosion-corrosion, missing material, deformed metal, excessive sludge/magnetite deposits, foreign objects, or worn material were not observed during any of the inspections.

Industry experience discussed above on identical primary separator structures in other plants does indicate that these structures are susceptible to erosion-corrosion degradation under non-uprated plant operating conditions. In the nominal case, the degradation reported in these other plants identified reduction in material thicknesses on the order of 25 percent of the original wall. A worst-case scenario would be through-wall holes in these structures.

Using this data as a guide, the potential exists that these same structures in the MPS3 Model F SGs may experience similar degradation. The steam drum components which potentially could have erosion-corrosion degradation are non-nuclear safety class parts. As noted in Section 3.3.1.4 of ANSI-51.1-1983, the design of non-nuclear safety class equipment must resist failure that could prevent safety class equipment from performing its nuclear safety function. In the case of potential erosion-corrosion of the steam drum components, the most significant condition, from a plant safety perspective, would be the potential for the generation of a loose part and subsequent impacting and sliding wear on the SG tubes.

In the event that a foreign object were to be generated in the steam drum region, the potential for it to exit the SG and enter the main steam, main feedwater, or auxiliary feedwater systems is negligible based on the following:

- For an object to exit the SG and enter the main steam system, it would be required to pass through the secondary moisture separator perforated plates, chevron vanes, and main steam venturi nozzles. An object capable of passing through this tortuous path would be of negligible size.

- An object would not be expected to enter the auxiliary feedwater system via the SG auxiliary feedwater discharge nozzle due to the constant forward flow through this nozzle during plant startup and power operations.
- An object would not be expected to enter the main feedwater system due to the design of the feedwater ring with J-nozzles. The forward flow of feedwater through the J-nozzles would preclude an object from entering this system during plant startup and power operations.

  If degradation does exist in the steam drum components in the MPS3 SGs in a manner similar to that experienced in other plants, based on the geometry of the components, such degradation will have a negligible impact upon the structural adequacy of the steam drum components affected. If continued wall loss were to cause thinned areas to link up, the fragment generated would not be expected to be of sufficient size to wear a tube to the minimum allowable wall thickness during the next operating cycle. Routine visual examinations on the secondary side of the tubesheet have successfully detected and retrieved foreign objects before safe operation of the plant has been compromised.

  Moreover, in the unlikely event that a loose part should come in contact with a SG tube during subsequent plant operation, the consequences of impacting and sliding wear on a tube by the loose part would be bounded by the accident analysis for a single tube rupture event.

In summary, inspections (visual and UT, where appropriate) performed prior to uprated plant operation of the steam drum components in the MPS3 Model F SGs (based upon References 1 through 7) have established a baseline against which future inspection results may be compared. These past inspection results have revealed localized signs of degradation in the feedwater ring requiring weld repairs to insure component integrity. Only very minor or no degradation has been reported for the other steam drum components. As operation at SPU will increase feedwater flow rates in the MPS3 SGs, coupled with the fact that erosion-corrosion has been experienced, it would be prudent to perform steam drum component inspections after every plant operating cycle, until all four SGs have been inspected at least twice in order to determine rates of erosion-corrosion degradation. Frequency of the inspection interval may be altered/extended once degradation rates are determined.

Prior to these recommended inspections, it is judged that if the increase in feedwater flow and steam velocities impact carbon steel components, it is more likely to produce a hole by flow assisted erosion-corrosion than to produce a loose part. Furthermore, in the unlikely event that a J-nozzle becomes separated from the feedwater ring due to erosion, its size would prohibit its travel down the annulus to the tubesheet.

In addition to the thermal-hydraulic conditions (e.g., feedwater flow velocity), secondary side water chemistry also plays an important role relative to the susceptibility to erosion-corrosion in the material in a steam drum component. It is, therefore, recommended that secondary-side water chemistry continue to be maintained within industry guidelines to provide an environment consistent with maintenance of controlled erosion-corrosion rates in secondary side carbon steel components.

2.2.2.5.2.8.5 References

1. Dominion Calculation Note 99ENG-01706-M3, Revision 0, Millstone Unit 3 Steam Generator J-Tube/Feedring Degradation Evaluation, May 14, 1999.

2. Dominion Calculation Change Notice (CCN) No. 1 to Calculation Note 99ENG-01706-M3, Revision 0, Millstone Unit 3 Steam Generator J-Tube/Feedring Degradation Evaluation, February 14, 2001.

3. Dominion document M3-EV-02-0008, Revision 0, Millstone Unit 3 Steam Generator Integrity Degradation Assessment, July 2, 2002.

4. Dominion document M3-EV-02-0035, Revision 0, Millstone Unit 3 Steam Generator Condition Monitoring and Operational Assessment Refueling Outage 8, October 7, 2002.

5. Dominion document M3-EV-04-0018, Revision 0, Millstone Unit 3 Steam Generator Condition Monitoring and Operational Assessment Refueling Outage 9, June 10, 2004.

6. M3-EV-05-0032, Revision 0, Millstone Unit 3 Steam Generator Condition Monitoring and Operational Assessment Refueling Outage 10, January 18, 2006.

7. Dominion document 25212-ER-06-0036, Revision 00, WNES Data Request NEU-06-20,Attachment 3, MPS3 RPUP: Steam Generator Evaluation Information," June 6, 2006.

2.2.2.5.2.9 Chemistry Evaluation

2.2.2.5.2.9.1 Introduction

Water chemistry of both the primary and secondary sides in nuclear power plants is controlled to maximize the long-term availability of PWR plants. In addition, primary water chemistry control can, and has been, effectively used to control radiation field buildup on ex-core surfaces. Guidelines have been provided to utilities by EPRI for primary and secondary chemistry (References 1 and 2). In addition, other organizations, such as NEI, have provided guidelines with respect to specific equipment (e.g., SGs) which are incorporated into the EPRI guidelines. These documents form an industry consensus approach for chemistry programs which are embodied in the plant Strategic Water Chemistry Plans for the primary and secondary systems.

Uprates in power potentially affect water chemistry of the nuclear power plant because of changes in temperature and/or flow rates.

2.2.2.5.2.9.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

- The operational parameters provided in Section 1.1, EPRI primary and secondary chemistry guidelines (References 1 and 2), strategic water chemistry plans for the primary and secondary sides at MPS3 and a summary of the chemistry for the previous 2 fuel cycles (References 1 through 4).
- MPS3 continues to operate at the primary and secondary chemistry in accordance with the strategic plans in References 3 and 4.

Acceptance Criteria

No specific changes in chemistry of either the primary or the secondary side are expected due to the uprating because the chemistry will continue to be controlled after the upgrade by plant procedures and specifications conforming to industry accepted guidelines and embodied in the MPS3 strategic water chemistry guidelines.

2.2.2.5.2.9.3 Description of Analyses and Evaluations

EPRI guidelines recognize the difference in design and operating characteristics of nuclear plants and prescribe that each plant generate strategic water chemistry plans for the primary and secondary water chemistries. This allows chemistry programs specifically tailored for each plant. References 3 and 4 provide those strategic plans for MPS3.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the SG components are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. The changes associated with operating the SGs at SPU conditions do not adversely affect the reactor coolant pressure boundary integrity. Thus, no new aging management effects are identified and no new commitments are required for MPS3 for the SGs beyond those described in this report. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.9.4 Results

MPS3's SG water chemistry is based on DNC's Master Manual 22, Millstone Chemistry Manual. This manual defines the mission and objectives of the primary and secondary elements of the chemistry program, along with associated mechanisms. The chemistry program is based on the latest industry guidance published by the Institute of Nuclear Power Operations (INPO) and Electric Power research Institute (EPRI). No significant changes to the primary or secondary chemistry programs are expected as a result of the SPU. The SG water chemistry is controlled based upon strategies contained in their primary and secondary strategic chemistry programs. No significant changes in the chemistry of either the primary or secondary side are expected due to the SPU. This is because the chemistry continues to be controlled after the upgrade by plant procedures and specifications conforming to industry accepted guidelines and embodied in the MPS3 strategic water chemistry documents. In addition, the temperatures stated in the design parameters in Section 1.1 are in the range where other plants control chemistry based on the same industry guidelines.

2.2.2.5.2.9.5 References

1. EPRI PWR Primary Water Chemistry Guidelines, Volume 1, Revision 5, TR-105714-V1R5, March 2003.

2. EPRI Pressurized Water Reactor Secondary Water Chemistry Guidelines, Revision 6, 1008224, Final Report, December, 2004.

3. MP-22-CHM-REF04, Strategic Primary Water Chemistry Plant for Millstone Station, Revision 002, April 12, 2006.

4. MP-22-CHM-REF03, Strategic Secondary Water Chemistry Plan for Millstone Unit 3, Revision 001, September 1, 2005.

2.2.2.5.2.10 RG 1.121 Analysis

2.2.2.5.2.10.1 Introduction

The heat transfer area of SGs in a PWR NSSS comprises over 50 percent of the total primary system pressure boundary. The SG tubing, therefore, represents a primary barrier against the release of radioactivity to the environment. For this reason, conservative design criteria have been established for the maintenance of tube structural integrity under the postulated design-basis-accident condition loadings in accordance with Section III of the ASME Code (Reference 1).

2.2.2.5.2.10.2 Input Parameters, Assumptions and Acceptance Criteria

Input Parameters and Assumptions

Input Parameters

Plant operating parameters at 3666 MWt NSSS uprated power (Section 1.1) are used to calculate the structural limits for condition monitoring and operational assessments.

Assumptions

Over a period of time under the influence of the operating loads and environment in the SG, some tubes may become degraded in local areas. Partially degraded tubes with a net wall thickness greater than the minimum acceptable tube wall thickness are satisfactory for continued service, provided that 1) leak-before-break is established, 2) the minimum required tube wall thickness is adjusted to take into account possible uncertainties in the eddy current inspection, and 3) an operational allowance is made for continued tube degradation until the next scheduled inspection.

Acceptance Criteria

MPS3 endorses NRC RG 1.121 (Reference 3), as stated in FSAR Section 1.8. RG 1.121 describes an acceptable method for establishing the limiting safe conditions of degradation in the tubes beyond which tubes found defective by the established in-service inspection shall be removed from service. The level of acceptable degradation is referred to as the “repair limit.” WCAP-16742 provides details of the methodology MPS3 intends to use post SPU to address RG 1.121 tube degradation safe limits.

A criterion for maintaining the SG tubes in a safe operating condition is defined in NEI-97-06, Rev. 2, and in particular the structural integrity performance criterion (SIPC). The SIPC is based on ensuring that there is reasonable assurance that a SG tube does not burst during normal or postulated accident conditions. Meeting the performance criterion provides reasonable assurance that the SG tubing remains capable of fulfilling its specific safety function of maintaining the reactor coolant pressure boundary integrity. Analyses have been performed to assess the effect of the revised SIPC on specific modes of degradation.

2.2.2.5.2.10.3 Description of Analyses and Evaluations

An analysis has been performed to define the structural limit for an assumed uniform thinning mode of degradation in both the axial and circumferential directions. The assumption of uniform thinning is generally regarded to result in a conservative structural limit for all flaw types occurring in the field. The allowable tube repair limit, in accordance with RG 1.121, is obtained by incorporating into the minimum required thickness, a growth allowance for continued operation until the next scheduled inspection, and also an allowance for eddy current measurement uncertainty. Analyses have been performed to establish the structural limit for the tube straight leg (free-span) region of the tube for degradation over an unlimited axial extent and for degradation over a limited axial extent at the tube support plate and AVB intersections.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the SG components are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. The changes associated with operating the SGs at SPU conditions do not adversely affect the reactor coolant pressure boundary integrity. Thus, no new aging management effects are identified and no new commitments are required for MPS3 for the SGs beyond those described in this report. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.10.4 Results

A summary of the tube structural limits as determined by the RG 1.121 analysis for both the high T_{avg} and low T_{avg} operating conditions is provided in Table 2.2.2.5.2.10-1.

Structural limits that could potentially be used in an operational assessment to address circumferential cracks in the U-bend region and the top tube support plate (TSP) were evaluated. The resulting structural limits for single-slit circumferential cracks at the top tube support plate and U-Bend region are summarized in Table 2.2.2.5.2.10-2.

The criteria governing structural integrity of SG tubes were developed in the 1970's and assumed uniform wall thinning. This led to the establishment of a through wall SG tube repair criteria (e.g. 40 percent) that has historically been incorporated into most pressurized water reactor (PWR) technical specifications and has been applied, in the absence of other repair criteria, to all forms of SG tube degradation where sizing techniques are available. This is the case with MPS3. Since the basis of the through wall depth criterion is generally 360^{o} wastage, it is generally considered to be conservative for other mechanisms of SG tube degradation. The 40 percent repair defined in the MPS3 plant technical specification (SR 4.4.5.4.a.6) is unaffected by the plant uprating.

The structural limit values calculated for the various forms of localized tube wall degradation and included in Table 2.2.2.5.2.10-1 will be used in both the condition monitoring and operational assessment completed for MPS3 in the future.

Condition monitoring involves the evaluation of the state of the SG tubing during an outage to verify that degraded tubing at the end of the previous operating interval (OI) met both the structural and leakage integrity performance criteria of NEI 97-06, Rev. 2.

The operational assessment is similar to condition monitoring, but requires that the degradation growth rate be applied to the tube degradation distribution at the beginning of the OI to predict the upcoming tube conditions at the end of the OI for a given SG. The predicted conditions at the end of the OI must meet both the structural and leakage performance criteria of NEI 97-06, Rev. 2.

2.2.2.5.2.10.5 References

1. ASME Boiler Level Pressure Vessel Code, Section III, Rules for Construction of Nuclear Vessels, 1971 Edition, Summer 1973 Addenda, American Society of Mechanical Engineers, New York, New York.

2. NEI-97-06, Rev. 2, Steam Generator Program Guidelines, May 2005.

3. US NRC Reg. Guide 1.121, Bases for Plugging Degraded PWR SG Tubes (for comment), 8/76.

2.2.2.5.2.11 Supports

2.2.2.5.2.11.1 Introduction

The primary equipment SG supports of the nuclear steam supply system (NSSS) as described in FSAR Section 5.4.14.1.2 and 5.4.14.2 are evaluated for the SPU program. The reactor coolant loop (RCL) piping loads on the primary equipment SG supports due to the parameters associated with the SPU as discussed in Section 2.2.2.1, NSSS Piping, Components and Supports, were reviewed for the impact on the existing RCL primary equipment SG supports design basis. The RCL piping loads on the SG supports due to deadweight, thermal expansion, operational basis earthquake (OBE), safe shutdown earthquake (SSE), loss-of-coolant accident (LOCA) and the pipe break loads per the current design basis were evaluated for the SPU program.

2.2.2.5.2.11.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The RCL piping loads on the SG supports due to deadweight, thermal expansion, seismic OBE, and seismic SSE, loss-of-coolant accident and pipe break loading cases are obtained from the piping system analyses for the SPU program as described in Section 2.2.2.1, NSSS Piping, Components and Supports.

Acceptance Criteria

The acceptance criteria for the MPS3 RCL primary equipment SG supports indicated in FSAR Section 3.9 and Table 5.4-18 are based upon the ASME Boiler and Pressure Vessel Code (B&PV), Section III, Subsection NF and Appendix F, 1974 Edition through 1974 Winter Addenda.

2.2.2.5.2.11.3 Description of Analyses and Evaluations

The SG support loads from the RCL piping system SPU analyses as described in Section 2.2.2.1, NSSS Piping, Components and Supports remain unchanged from the current design basis SG support loads.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the SG supports. The aging evaluations approved by the NRC in sections 2.4B.3 and 3.5B of the License Renewal SER for the SG supports remain valid for the SPU conditions. Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.5.2.11.4 Results

Stresses for SG support components for SPU conditions for the SG vertical and lateral supports were evaluated. In all cases, the stresses for all SG support components satisfy applicable acceptance criteria.

2.2.2.5.3 Conclusion

DNC has reviewed the evaluations related to the structural integrity of pressure-retaining components and their supports. For the reasons set forth above, DNC concludes that the evaluations have adequately addressed the effects of the proposed SPU on these components and their supports. Based on the above, DNC further concludes that the evaluations have demonstrated that pressure-retaining components and their supports will continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

Table 2.2.2.5.2.1-1 MPS3 - Steam Generator Performance Characteristics with 3666 MWt NSSS SPU

Case	Ref. Case 100% Power	1 107% Power, Reduced Inlet Temp	2 107% Power, Reduced Inlet Temp, 10% Plugging	3 107% Power; Elevated Inlet Temp	4 107% Power, Elevated Inlet Temp, 10% Plugging	5 107% Power, Elevated Inlet Temp	6 107% Power, Elevated Inlet Temp, 10% Plugging
SG T_{avg}, °F	**587**	**571.5**	**571.5**	**589.5**	**589.5**	**581.5**	**581.5**
Operating Conditions							
Power, %	100	107.04	107.04	107.04	107.04	107.04	107.04
NSSS Power, MWt	3425	3666	3666	3666	3666	3666	3666
Power, MWt/SG	856.3	916.5	916.5	916.5	916.5	916.5	916.5
Primary Temperature							
SG T_{hot}, °F	617.20	605.79	605.79	622.79	622.79	615.28	615.28
SG T_{cold}, °F	556.80	537.21	537.21	556.21	556.21	547.72	547.72
SG T_{avg}, °F	587.00	571.50	571.50	589.50	589.50	581.50	581.50
Primary Flow, gpm	94600	90800	90800	90800	90800	90800	90800
Feed Temperature, °F	436.2	445.3/390	445.3/390	445.3/390	445.3/390	445.3/390	445.3/390
Fouling, 10^{-6} hr-ft^2-°F/Btu	50	60	60	60	60	60	60
Plugging, %	0	0	10	0	10	0	10
Operating Characteristics(1)							
Steam Flow, 10^6 lbm/hr	3.754	4.042 / 3.751	4.039 / 3.748	4.068 / 3.773	4.064 / 3.770	4.055 / 3.762	4.052 / 3.759

Table 2.2.2.5.2.1-1 MPS3 - Steam Generator Performance Characteristics with 3666 MWt NSSS SPU

Case	Ref. Case 100% Power	1	2	3	4	5	6
		107% Power, Reduced Inlet Temp	**107% Power, Reduced Inlet Temp, 10% Plugging**	**107% Power; Elevated Inlet Temp**	**107% Power, Elevated Inlet Temp, 10% Plugging**	**107% Power, Elevated Inlet Temp**	**107% Power, Elevated Inlet Temp, 10% Plugging**
SG T_{avg}, °F	**587**	**571.5**	**571.5**	**589.5**	**589.5**	**581.5**	**581.5**
Steam Temperature, °F	542.23	520.80 / 520.96	518.30 / 518.40	540.49 / 540.61	538.02 / 538.14	531.74 / 531.87	529.24 / 529.38
Steam Pressure(2), psia	980.76	818.16 / 819.29	800.47 / 801.62	966.76 / 967.71	947.01 / 947.98	898.35 / 899.38	879.55 / 880.60
Circulation Ratio	[ ] a,c	[ ] a,c	[ ] a,c	[ ] a,c	[ ] a,c	[ ] a,c	[ ] a,c

Table 2.2.2.5.2.1-1 MPS3 - Steam Generator Performance Characteristics with 3666 MWt NSSS SPU

Case	Ref. Case 100% Power	1 107% Power, Reduced Inlet Temp	2 107% Power, Reduced Inlet Temp, 10% Plugging	3 107% Power; Elevated Inlet Temp	4 107% Power, Elevated Inlet Temp, 10% Plugging	5 107% Power, Elevated Inlet Temp	6 107% Power, Elevated Inlet Temp, 10% Plugging
SG T_{avg}, °F	**587**	**571.5**	**571.5**	**589.5**	**589.5**	**581.5**	**581.5**
Bundle Liquid Flow, 10^6 lbm/hr							
Modified Separator Parameter ($w_s^2 v_s^{0.4}$)							
Average Heat Flux, Btu/hr-ft^2							
Total Secondary $\Delta P^{(3)}$, psi							
Downcomer Velocity, ft/sec							
Downcomer Subcooling, °F							
S/G Secondary Side Mass, lbm							
Damping Factor, hr^{-1}							
Peak (X/X_{DNB}) Ratio$^{(4)}$							
Moisture Carryover (Wt%)							

a,c

Note:

1. The results shown are applicable for zero to 100 gpm blowdown rate.
2. Section 1.1 steam pressures differ slightly from these values as a result of different codes and different calculations for internal pressure drop.

Table 2.2.2.5.2.1-1 MPS3 - Steam Generator Performance Characteristics with 3666 MWt NSSS SPU

Case	Ref. Case 100% Power	1 107% Power, Reduced Inlet Temp	2 107% Power, Reduced Inlet Temp, 10% Plugging	3 107% Power; Elevated Inlet Temp	4 107% Power, Elevated Inlet Temp, 10% Plugging	5 107% Power, Elevated Inlet Temp	6 107% Power, Elevated Inlet Temp, 10% Plugging
SG T_{avg}, °F	**587**	**571.5**	**571.5**	**589.5**	**589.5**	**581.5**	**581.5**
3. The pressure drop values represent the differences in the pressures calculated at the feedwater nozzle inlet and at the steam nozzle outlet. They are based on 100gpm blowdown rate.							
4. Ratio of local quality at DNB on ATHOS runs. ATHOS analysis was performed only for the limiting case, i.e., the case with 10% plugging and original inlet temperature.							

Table 2.2.2.5.2.2-1 MPS3 SPU Structural Integrity Evaluation Summary Primary Side Components

		Stress (ksi)/Fatigue		Allowable (ksi)/Fatigue	Comments
Component	**Stress Category**	**Baseline[3]**	**Uprate**		
Divider Plate	$\lvert P_m+P_b+Q \rvert$ [1] - (Section 1, OS)			a,c	w/ Hydrotest
	$\lvert P_m+P_b+Q \rvert$ [1] - (Section 1, OS)				w/o Hydrotest
	Fatigue - (Hot Leg Node 35)				w/ COPPS
Tubesheet & Shell Junction	$\lvert P_m+P_b+Q \rvert$ - (Location 1, LS) [2]				simplified elastic-plastic analysis was performed
	Fatigue - (Location 1, LS)				w/ COPPS
	Fatigue - (Location 6, IS)				w/ COPPS
	Fatigue - (Location 4, IS)				w/ COPPS
Tube-to-Tubesheet Weld	$\lvert P_m+P_b+Q \rvert$ - (Section 2(s), [2] Weld Root)				Evaluated inelastically in original analysis
	Fatigue – (Section 3, Weld Toe)				w/ COPPS
Tubes	$\lvert P_m+P_b+Q \rvert$ - (Section A-A)				
	Fatigue - (Section A-A)				w/ COPPS
Blowdown Pipe	| Pm + Pb + Q| - (Section 4, Weld Root) [2]				simplified elastic-plastic analysis was performed in baseline analysis
	Fatigue - (Section 5, Weld Toe)				w/ COPPS
DMIMS	| Pm + Pb + Q | - (Lwr shell junction, outer surface)				
	Fatigue				

Notes:

1. The divider plate elastic results exceed $3S_m$ with hydrotest. Plastic fatigue usage was calculated separately due to hydrotest based on the strain range between the two hydro tests after shakedown, per NB-3228.3 of the Code, to show acceptability.
2. The stress range exceeds $3S_m$. A simplified elastic-plastic analysis was done per NB-3228.5 of the Code to show acceptability.
3. Includes the effect of COPPS. The baseline fatigue analysis did not include COPPS.

Table 2.2.2.5.2.2-2 MPS3 SPU Structural Integrity Evaluation Summary Secondary Side Components

Component	Stress Category	Stress (ksi) / Fatigue Baseline	Stress (ksi) / Fatigue Uprate	Allowable (ksi)/Fatigue	Comments
Main Feedwater Nozzle	$\lvert P_m+P_b+Q \rvert$ - (Section A-A) [1]		a,c	90.00	Simplified elastic-plastic analysis was performed
	$\lvert P_m+P_b+Q \rvert$ - (Section B-B)			90.00	
	Fatigue - (Section A-A) (FW temp=445.3°F)			1.00	
	Fatigue - (Section B-B) (FW temp = 445.3°F)			1.00	
	Fatigue - (Section B-B) (FW temp = 390.0°F)			1.00	Additional thermal stress did not have any impact on the total fatigue usage
Secondary Manway Bolt	$\lvert P_m+P_b+Q \rvert$ - (Bolt IS)			86.60	
	Fatigue - (Bolt IS) [2]			1.00	
Steam Nozzle	$\lvert P_m+P_b+Q \rvert$ - (Sec A-A)			90.00	
	$\lvert P_m+P_b+Q \rvert$ - (Insert Fillet Weld, ASN-1 Inside)			78.00	
	Fatigue - (Section D-D, Outside)			1.00	
	Fatigue - (Insert Fillet Weld, ASN-1 Outside)			1.00	
Support Ring	$\lvert P_m+P_b+Q \rvert$ - (Inside Surface) [1]			56.10	Simplified elastic-plastic analysis was performed
	Fatigue - (Inside Surface)			1.00	
Wrapper Support System	$\lvert P_m+P_b+Q \rvert$ - (Shear Lug, Section B-B)			44.10	
	Fatigue - (Anti-Rotation Keys) [3]			1.00	
DMIMS	$\lvert P_m+P_b+Q \rvert$ - Upper Junction, outer surface			90.0	
	Fatigue			1.00	

Notes:
1. Support ring exceeds $3S_m$. A simplified elastic-plastic analysis was done per NB-3228.5 of the Code to show acceptability.
2. Fatigue usage shown is for 30-year replacement schedule.
3. Fatigue usages are very small and there is no impact due to the uprate.

Table 2.2.2.5.2.3-1 Summary of Design Pressure Differential (Delta-P) for MPS3 SPU Program

Case	Limiting Transient	Condition	Delta-P (psi)	Allowable (psi)
High T_{avg}, 10% Tube Plugging	Loop Out of Service Shutdown Reactor Trip, Cooldown w/ SI	Normal Upset		a,c
Low T_{avg}, 10% Tube Plugging	Loop Out of Service Shutdown Reactor Trip, Cooldown w/ SI	Normal Upset		

Table 2.2.2.5.2.5-1 MPS3 Steam Generator Performance Characteristics with SPU (3666 MWt NSSS Power)

Case	Ref. Case 100% Power	1	2	3	4
		107% Power, Reduced Inlet Temp		107% Power; Elevated Inlet Temp	
SG T_{avg}, °F	587.0	571.5	571.5	589.5	589.5
Operating Conditions					
Power, %	100	107.04	107.04	107.04	107.04
NSSS Power, MWt	3425	3666	3666	3666	3666
Power, MWt/SG	856.3	916.5	916.5	916.5	916.5
Primary Temperature					
SG T_{hot}, °F	617.2	605.79	605.79	622.79	622.79
SG T_{cold}, °F	556.8	537.21	537.21	556.21	556.21
SG T_{avg}, °F	587.00	571.50	571.50	589.50	589.50
Primary Flow, gpm	94600	90800	90800	90800	90800
Feed Temperature, °F	436.2	445.3/390	445.3/390	445.3/390	445.3/390
Fouling, 10^{-6} hr-ft^2-°F/Btu	50	60	60	60	60
Plugging, %	0	0	10	0	10
Operating Characteristics(1)					
Steam Flow, 10^6 lbm/hr	3.754	4.042/3.751	4.039/3.748	4.068/3.773	4.064/3.770
Steam Temperature, °F	542.23	520.80/520.96	518.30/518.40	540.49/540.61	538.02/538.14
Steam Pressure(2), psia	980.76	818.16/819.29	800.47/801.62	966.76/967.71	947.01/947.98
Circulation Ratio					a,c
Bundle Liquid Flow, 10^6 lbm/hr					

Table 2.2.2.5.2.5-1 MPS3 Steam Generator Performance Characteristics with SPU (3666 MWt NSSS Power)

U-Bend Conditions	
Bundle Exit Fluid Density, lbm/ft^3	a,c
Bundle Exit Volumetric Flow, ft^3/sec	
Relative Mixture Velocity, V	
Relative Mixture, V^2	
Turbulence, $(V^2)^2$	
Bundle Entrance Conditions	
Mass Flow rate, 10^6 lbm/hr	
Fluid Temperature, °F	
Fluid Density, lbm/ft^3	
Volumetric Flow Rate, ft^3/sec	
Relative Fluid Velocity, V	
Relative Fluid, V^2	
Turbulence, $(V^2)^2$	

Notes:
1. The results shown are applicable for zero to 100 gpm blowdown rate.
2. Section 1.1 steam pressures differ slightly from these values as a result of different codes used and different calculations for internal pressure drop.

Table 2.2.2.5.2.6-1 Summary of Relevant Wear Time to Density and Velocity Ratios

Uprate Case	ρV^2 Ratio Value At Downcomer	
	ρV^2 Ratio	$(\rho V^2)^2$ Ratio
1 (Feed Temp = 445.3°F)	a,c,e	a,c,e
1 (Feed Temp = 390°F)		
2 (Feed Temp = 445.3°F)		
2 (Feed Temp = 390°F)		
3 (Feed Temp = 445.3°F)		
3 (Feed Temp = 390°F)		
4 (Feed Temp = 445.3°F)		
4 (Feed Temp = 390°F)		
5 (Feed Temp = 445.3°F)		
5 (Feed Temp = 390°F)		
6 (Feed Temp = 445.3°F)		
6 (Feed Temp = 390°F)		
Maximum Value		

Table 2.2.2.5.2.10-1 Summary of Tube Structural Limits
(RG 1.121 Analysis)

Location/ Wear Scar Length	Parameter	High T_{avg} Value	Low T_{avg} Value
Straight Leg (>1.5 inch)	t_{min} (inch)		a,c
	Structural Limit (%)[1]		
FDB / [ ][a,c]	t_{min} (inch)		
	Structural Limit (%)[1]		
TSP / [ ][a,c]	t_{min} (inch)		
	Structural Limit (%)[1]		
TSP / [ ][a,c]	t_{min} (inch)		
	Structural Limit (%)[1]		
AVB / [ ][a,c (2)]	t_{min} (inch)		
	Structural Limit (%)[1]		

Notes:

1. Structural Limit = $[(t_{nom} - t_{min}) / t_{nom}] \times 100\%$
   $t_{nom} = 0.040$ in
2. For Tube/AVB tangent points, straight leg structural limits apply.
   Tube/AVB tangent points correspond to Row 7 for the inner set of AVBs, Row 20 for the middle set of AVBs, and Row 31 for the outer set of AVBs.

**Table 2.2.2.5.2.10-2 Summary of Tube Structural Limits
Single Slit Circumferential Cracks
Top Tube Support Plate and U-Bend Region**

High T_{avg}					
Top Tube Support Plate			**U-Bend Region**		
Tube Rows	**Percent Degraded Area**	**Arc Length**	**Tube Rows**	**Percent Degraded Area**	**Arc Length**
1–34	[ ]^{a,c}	[ ]^{a,c}	1–34	[ ]^{a,c}	[ ]^{a,c}
35–48	[ ]^{a,c}	[ ]^{a,c}	35–48	[ ]^{a,c}	[ ]^{a,c}
49–59	[ ]^{a,c}	[ ]^{a,c}	49–59	[ ]^{a,c}	[ ]^{a,c}
Low T_{avg}					
Top Tube Support Plate			**U-Bend Region**		
Tube Rows	**Percent Degraded Area**	**Arc Length**	**Tube Rows**	**Percent Degraded Area**	**Arc Length**
1–59	[ ]^{a,c}	[ ]^{a,c}	1–48	[ ]^{a,c}	[ ]^{a,c}
			49–59	[ ]^{a,c}	[ ]^{a,c}

2.2.2.6 Reactor Coolant Pumps and Supports

2.2.2.6.1 Introduction

The RCP and its supports are reviewed as part of the SPU. The RCPs are described in FSAR Sections 3.9N, 5.1 and 5.4.1. The RCP supports are described in FSAR Section 5.4.14. MPS3 is a four loop Westinghouse NSSS design. Each loop contains a vertical, single stage, controlled leakage centrifugal RCP. The Regulatory Evaluation included in Section 2.2.2 also applies to the RCP and its supports.

The functions of the RCP are:

To maintain an adequate core cooling flow rate by circulating a large volume of primary coolant water at high temperature and pressure through the RCS

To provide adequate flow coastdown to prevent core damage in the event of a simultaneous loss of power to all RCPs

To provide a portion of the RCPB

The Technical Evaluation included as part of this LR describes the input parameters, assumptions and acceptance criteria used to evaluate RCP performance relative to the SPU.

A summary regarding the adequacy of the RCPs and their supports under SPU conditions concludes this LR subsection.

Current Licensing Basis

The generic CLB in Section 2.2.2 applies to the RCPs and their supports, with the following amplifications.

The RCPs are single speed centrifugal units driven by air-cooled, three phase induction motors. The shaft is vertical with the motor mounted above the pumps. A flywheel on the shaft above the motor provides additional inertia to extend pump coastdown. The inlet is at the bottom of the pump; discharge is on the side. The RCPs employ a controlled leakage seal assembly. There are four RCPs. FSAR Table 5.4-1 provides RCP design parameters.

FSAR Table 5.2-2 indicates that the internals portion of the RCP, which contact or may contact primary system fluid, including forgings, castings, tube and pipe, pressure plates, bars and closure bolting, are made from stainless steel.

FSAR Section 3.2 and Table 3.2-1 provide Seismic Classification, Quality Group, QA Category, and applicable ASME Code Category for Category 1 SSCs such as the RCPs. FSAR Table 3.2-1 shows that certain parts of the RCP (casing, main flange, thermal barrier, seal housing and pressure retaining bolting) are classified as ASME Section III, Class 1, ANS Safety Class 1. The balance of the RCP components (motors, seal housings, etc.) are classified as ANS Safety Class 2. RCP supports are designed to meet the same Safety Class designation as the components they support. The RCP supports are Safety Class 1.

FSAR Section 5.4.14.1.3 indicates that the RCP is supported by three pin-ended columns that provide vertical support while allowing free movement in the horizontal plane. Three independent hydraulic snubber assemblies, connected to the pump support and the reactor shield wall, provide lateral support for the pump during dynamic loading conditions while allowing thermal expansion of the RCS.

The RCP and supports are designed to withstand stresses originating from various operating design transients. FSAR Tables 3.9N-1 and 5.4-18 summarize RCS design transients for normal, upset, emergency, faulted and test conditions. It indicates that the RCS and the RCP are designed for 200 heat up transients of 100°F per hour, and an additional 200 cool down transients of 100°F per hour. Additionally, the RCPs are subject to an assumed 3800 pump start up and shut down transients as part of normal plant operation.

The MPS3 RCP is tested and inspected per the requirements of Section XI of the ASME B&PV Code, 1989 Edition, no addenda. The RCP flywheels are subject to an ISI once every 10 years.

The RCPs and their supports were evaluated for continued acceptability for plant license renewal. NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3," dated August 1, 2005, documents the results of that review. NUREG-1838, Sections 2.3B.1.3 and 3.1B are applicable to the RCPs. NUREG-1838 Sections 2.4B.3 and 3.5B are applicable to the RCP supports.

2.2.2.6.2 Technical Evaluation

2.2.2.6.2.1 Input Parameters, Assumptions, and Acceptance Criteria

The major inputs used in the RCP evaluation are the SPU parameters provided in Section 1.1, Nuclear Steam Supply System Parameters, and the SPU NSSS design transients provided in Section 2.2.6, NSSS Design Transients. These LR sections provide the operating and transient conditions for the SPU conditions. The RCPs are installed in the RCS cold leg, between the steam generator outlet and the reactor vessel inlet. Therefore, the cold-leg temperatures and the cold-leg transients are applicable to the RCPs. These operating and transient conditions differ in some cases from those specified in the RCP equipment specification, to which the MPS3 RCPs were already designed and analyzed.

The SPU parameters (Section 1.1) and SPU NSSS system design transient parameters (Section 2.2.6) were considered in the SPU evaluations. These two LR sections contain all of the pressure or thermal-hydraulic design parameters due to the SPU that would affect the reactor coolant pumps or their supports. Design loads under SPU conditions were found to be less than or equal in magnitude to the loads that were previously analyzed, with no changes to the load application points or number of occurrences.

The inputs for seismic analysis of the RCP, including seismic accelerations and pump component mass and stiffness, have not changed due to the SPU conditions. The power required to operate the pump under the SPU conditions remains within the capability of the motor. Therefore, hardware changes are not required and seismic analyses and non-pressure boundary component evaluations are unaffected by the SPU. The evaluation of the RCPs for the SPU compared the operating temperatures and pressures defined in the SPU parameters to the pressures and temperatures considered in previous analyses of the RCPs. In addition, the NSSS design transients for the SPU were compared to the transients considered in previous analyses. Where temperatures, pressures, and NSSS transients considered in previous analyses enveloped the temperatures, pressures, and NSSS transients defined for the SPU, no additional analysis was required. For the inputs that were not enveloped by the previously analyzed parameters, RCP structural analyses and evaluations were performed as necessary to incorporate the revised design inputs. Where these analyses and evaluations were required, the acceptance criteria were that the MPS3 RCP pressure boundary components meet the stress limits and fatigue usage requirements of the ASME Code, Section III for plant operation with the SPU conditions.

The RCP motors were evaluated for the MPS3 SPU parameters provided in Section 1.1, Nuclear Steam Supply System Parameters, and best-estimate flows at an assumed core power of 3650 MWt. The input parameters considered in the evaluation of the reactor coolant pump motors for the MPS3 SPU Program are for a range of SG outlet temperatures from 537.0° to 556.0° F. The range of best-estimate flows considered is from 99,700 to 97,300 gpm/loop for a range of SGTP from 0 to 10 percent SGTP at full power operation. For the cold condition (70°F), the range of best-estimate flows considered is from 94,200 to 91,600 gpm/loop for 0 to 10 percent SGTP.

The steam generator outlet temperatures and best-estimate flows were considered in a hydraulic analysis using the operating characteristics of the MPS3 RCPs. This hydraulic analysis calculates the power requirements for the impeller that operates at the highest power for both hot and cold operation. The RCP motors were evaluated to confirm that they continue to meet their design requirements.

The RCL piping loads on the RCP supports due to deadweight, thermal expansion, seismic OBE, and seismic SSE loading cases are the same as described in the original design basis as described in Section 2.2.2.1, NSSS Piping, Components and Supports. The LOCA and the pipe break analyses from the current design basis remains valid for the SPU program.

The acceptance criteria for the MPS3 RCL piping and RCP supports are as presented in the CLB and as described in FSAR Section 3.9B.1.4 for the RCL and 3.9B.3.4 for the RCP supports and are based upon the ASME B&PV Code.

2.2.2.6.2.2 Description of Analyses and Evaluations

2.2.2.6.2.2.1 Operating Temperature and Pressure

The SPU parameters (see Section 1.1, Nuclear Steam Supply System Parameters) for MPS3 were used to evaluate the acceptability of the RCPs. In the SPU parameters for MPS3, there are no changes from the current reactor coolant pressure of 2250 psia for any of the SPU cases. For SPU, the reactor coolant system cold-leg temperature (T_{cold}), defined by the vessel inlet (RCP outlet) temperature, is a maximum of 556.4°F and a minimum of 537.4° F. Since lower temperatures in the operating range result in higher allowable stresses for the pressure boundary materials, a decrease in operating temperature is conservative. The maximum SPU RCS T_{cold} is less than the equipment specification operating temperature of 556.8°F. Since none of the SPU temperatures exceed the previously considered temperature and the pressure does not change, the SPU NSSS parameters are bounded by those defined in the equipment specification. No further evaluation of the Reactor Coolant Pump pressure boundary integrity was required for the operating temperature and pressure associated with the MPS3 SPU.

2.2.2.6.2.2.2 Transient Discussion

The NSSS design transients were recalculated for the MPS3 SPU Program and are provided in Section 2.2.6, NSSS Design Transients. The cold-leg transients were applicable to the RCP evaluation. The recalculated design transients had some temperature and pressure changes that were different than the transients given in the equipment specification or used in the original analyses.

Since there was some variation from the cold-leg transients considered in the original analyses, a comparison of the temperature changes (ΔT) and the pressure changes (ΔP) was performed to determine if the MPS3 SPU Program transients were bounded or covered by the original transients.

The qualification of the pump is based on using a fatigue waiver as defined in Section NB-3222.4(d) of the ASME Code. Per NB-3222.4(d), an analysis for cyclic operation is not required and it may be assumed that the peak stress limit discussed in NB-3222.4(d) is satisfied if the specified normal and upset conditions meet the six conditions stipulated in NB-3222.4(d) (1) through (6). If any of the six conditions are not met for a particular component, then it is necessary to (re)calculate the cumulative usage factor for that component with the requirement that the cumulative usage factor must be less than 1.0.

2.2.2.6.2.2.3 Main Closure Stress Analysis

The main closure design pressure components consist of the main flange bolting ring, thermal barrier flange, main closure bolts, and seal housing. This analysis showed that the only transients with a potential for affecting the fatigue usage of the main closure components are the heatup and cooldown transients and the newly defined COPS transient. The heatup and cooldown transients remained unchanged for SPU. While the number of pressure cycles associated with the COPS transient impacted the fatigue waiver of the bolting ring, the maximum (bounding) pressure and thermal transient ranges were unchanged. Therefore, the stress ranges remained the same and the cumulative usage factor for the bolting ring and the main closure bolts were recalculated. The values of the cumulative usage factors are shown in Table 2.2.2.6-1.

2.2.2.6.2.2.4 Pump Casing Stress Analysis

In most cases, the MPS3 SPU Program transients were very similar to the transients considered in the original analysis. The exception to this was the addition of the COPS transient event which did not exist in the original analyses. The COPS temperature transient has been shown to induce general casing section temperature range changes bounded by the original analysis temperature transients. Similarly, the range of COPS pressure transient is bounded by original analysis pressure transients. Therefore, COPS did not change the existing temperature and pressure stress ranges and the effect of the COPS transient was assessed by simply evaluating the changes to the cumulative usage from the additional 10 thermal cycles and 6000 pressure cycles. The values of the cumulative usage factor are shown in Table 2.2.2.6-1.

2.2.2.6.2.2.5 Support Foot Analysis

The support foot was considered a structural member in the original stress analysis and was analyzed only for mechanical loads. There was no transient analysis. Thus, changes to the NSSS design transients associated with the SPU do not affect the support foot analysis.

2.2.2.6.2.2.6 Flow Induced Vibration Analysis

Analysis of flow induced vibration is not included in the licensing basis for the MPS3 RCPs. The change in RCS flow under SPU conditions is not significant considering the heavy construction of the RCPs.

2.2.2.6.2.2.7 RCP Motors

For the RCP motors, a hydraulic analysis was performed using best estimate flows and modeling the characteristics of the MPS3 RCPs. The hydraulic analysis is used to calculate brake horsepower for the RCP motors, the loading on the thrust bearings, and the torque-speed curve for the RCP motors.

The RCP motors were evaluated in the following three areas for the MPS3 SPU conditions:

Continuous operation at hot-loop (100 percent power) conditions

Continuous operation at cold-loop (70°F) conditions

Starting across the line with a minimum 75 percent starting voltage

Thrust bearing loading

The results of this evaluation are discussed in Section 2.2.2.6.2.3.

2.2.2.6.2.2.8 RCP Supports

The RCP loads and RCP support reaction loads are not impacted by the SPU

2.2.2.6.2.2.9 Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal Application for the RCP and supports. The aging evaluations approved by the NRC in Sections 2.3B.1.3 and 3.1B of the License Renewal SER for the RCP remain valid for the SPU conditions. The aging evaluations approved by the NRC in Sections 2.4B.3 and 3.5B of the License Renewal SER for the RCP supports remain valid for the SPU conditions. As approved by the NRC per Sections 2.3B.1.3, 3.1B, 2.4B.3, and 3.5B in the License Renewal SER, the evaluations for aging management performed for the RCP and support remain valid for the SPU conditions. Additionally, the NRC staff evaluation of RCP flywheel integrity for extended plant operation, as discussed and accepted in License Renewal SER Section 4.7B.2.2, remains valid for SPU conditions.

2.2.2.6.2.3 Results

The operating temperature and pressure discussion presented in Section 2.2.2.6.2.2.1 showed that the operating temperatures and pressures are bounded by those considered for the original stress analysis.

The results of the design transient evaluation of the RCP pressure retaining components are given in Table 2.2.2.6-1. Some of these components required the recalculation of cumulative usage factors for the SPU conditions, while for other components, no changes to the cumulative usage factors were necessary. All of the cumulative usage factors given in Table 2.2.2.6-1 are within the allowable values given in the ASME Code.

The RCP loads and RCP support reaction loads are not impacted by the SPU

The RCP motor brake horsepower results from the hydraulic analysis are as given in Table 2.2.2.6-2, Reactor Coolant Pump Motor Performance Summary. The worst-case hot-loop load under the SPU operating conditions is 7201 hp. The worst-case cold-loop load under the SPU operating conditions is 9183 hp. These loadings are more than the motor nameplate ratings of 7000 hp for hot-loop operation and 8750 hp for cold-loop operation. This necessitates the need to calculate the predicted stator winding temperature rise value for both the hot-loop and cold-loop conditions.

Per the equipment specification, the motor is required to drive the pump continuously under hot-loop conditions without exceeding a temperature rise of 75°C (corresponding to the NEMA MG-1, Section III, Part 20.8, Class B temperature rise limit in a 50°C ambient) and under cold-loop conditions without exceeding a temperature rise of 100°C (corresponding to NEMA Class F in a 50°C ambient). The RCP motors are acceptable for operation at these increased steady state power output levels because the calculated stator winding temperature rise values for both hot and cold loop conditions do not exceed that allowed by the equipment specification. The predicted temperature rises will be 65.9°C (hot) and 88.3°C (cold) whereas the Class B and Class F insulation ratings allow stator temperature rises above the 50°C ambient of 75°C (hot) and 100°C (cold).

Per the equipment specification, the motor is required to start across the line with a minimum 75 percent starting voltage against the reverse flow of the of pumps running at full speed, under cold-loop conditions. The limiting component for this type of starting duty is the rotor cage winding, which has design limits per the equipment specification of a 300°C temperature rise on the rotor bars and a 50°C temperature rise on the rotor resistance rings. Using the torque-speed curve from the hydraulic analysis, a conservative all-heat-stored analysis showed a bar temperature rise of 241.4°C and a resistance ring temperature rise of 27.96°C, both of which are within their allowable limit.

The thrust-bearing loading used for the motor design is given in the equipment specifications for the motor. The analysis for the MPS3 SPU conditions indicates an increase in the downward impeller thrust from 46,000 lb to 54,473 lb for hot-loop operation, and an increase from 66,000 lb to 73,213 lb for cold-loop operation. For hot-loop operation, this increase in impeller down thrust results in a net decrease in the up thrust loading on the thrust bearing during normal operation. For cold-loop operation, the increase in impeller down thrust loading was calculated to increase the down thrust loading by 7.9 percent. In comparison to the normal operating thrust bearing load given in the equipment specifications, these changes are not significant and the thrust bearings are acceptable for the SPU loads.

There are no changes required as a result of the SPU for the reactor coolant pumps and motors supporting systems such as cooling water, seal injection flow, or lubricating oil/lube oil spillage collection.

2.2.2.6.3 Conclusion

DNC has reviewed the evaluations related to the structural integrity of the RCP and supports and concludes that the evaluations have adequately addressed the effects of the proposed SPU on the RCP and supports. DNC further concludes that the evaluations have demonstrated that the RCP and supports continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14 and GDC-15 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the design of the RCP and supports.

2.2.2.6.4 References

1. ASME Boiler and Pressure Vessel (B&PV) Code, 1974 Edition with Addenda through the Summer 1974 Addenda, Section III, Division 1, “Nuclear Power Plant Components”, Subsection NB, “Class 1 Components”, The American Society of Mechanical Engineers, New York, New York.

Table 2.2.2.6-1
MPS3 RCP Pressure Retaining Component Cumulative Usage Factors

Component	Cumulative Usage Factor from Original Analyses	Cumulative Usage Factor for SPU	Allowable Cumulative Usage Factor
Bolting Ring	Fatigue Waiver	0.094	1.0
Main Closure Bolts	Fatigue Waiver	0.45	1.0
Thermal Barrier Flange	Fatigue Waiver	Fatigue Waiver	N/A
Thermal Barrier Flange Holes	0.829	No Change	1.0
Heat Exchanger Coils	0.235	No Change	1.0
Seal Housing and Bolts	Fatigue Waiver	Fatigue Waiver	N/A
Casing	Fatigue Waiver	Fatigue Waiver	N/A
Casing/Discharge Nozzle Junction	0.209	0.210	1.0
Weir	0.433	0.440	1.0

Table 2.2.2.6-2
Reactor Coolant Pump Motor Performance Summary

	Current Condition or Rating	Uprating Case	Change or Margin
Hot Loop Load	7000 hp (Nameplate Rating)	7201 hp	+201 hp
Cold Loop Load	8750 hp (Nameplate Rating)	9183 hp	+433 hp
Hot Loop Stator Temperature Rise	62.2°C (by test) (75°C NEMA limit)	65.9°C	+3.7°C (9.1°C margin)
Cold Loop Stator Temperature Rise	82.9°C (estimated) (100°C NEMA limit)	88.3°C	+5.4°C (11.7 °C margin)
Starting Rotor Bar Temperature Rise	300°C (Design Limit)	241.4°C	58.6°C margin
Starting Rotor Resistance Ring Temperature Rise	50°C (Design Limit)	27.96°C	22.04°C margin
Axial Thrust (Hot Loop)	–46,000 lb (Design Condition)	-54,473 lb	8,473 lb increase
Axial Thrust (Cold Loop)	–66,000 lb (Design Condition)	-73,213 lb	7,213 lb increase

2.2.2.7 Pressurizer and Supports

2.2.2.7.1 Introduction

The pressurizer and supports are reviewed as part of the SPU. FSAR Section 5.4.10 describes the pressurizer. FSAR Section 5.4.14.1.4 describes the pressurizer support system. The pressurizer provides a point in the RCS where liquid and vapor can be maintained in equilibrium under saturated conditions for pressure and control purposes, for steady state operation and during transients. The Regulatory Evaluation included in Section 2.2.2 also applies to the pressurizer and its supports.

The Technical Evaluation included as part of this LR describes the input parameters, assumptions and acceptance criteria used to evaluate pressurizer performance relative to the SPU.

A summary regarding the adequacy of the pressurizer and its supports under SPU conditions concludes this LR subsection.

Current Licensing Basis

The generic CLB in Section 2.2.2 applies to the pressurizer and its supports, with the following amplifications.

FSAR Section 3.2 and Table 3.2-1 provide Seismic Classification, Quality Group, QA Category, and applicable ASME Code Category for Category 1 SSCs such as the pressurizer. FSAR Table 3.2-1 states in part that, with the exception of its heaters, the pressurizer is classified as ASME Section III, Class 1, ANS Safety Class 1. The pressurizer supports are designed to meet the same Safety Class designation as the component they support. The pressurizer supports are Safety Class 1. FSAR Table 5.4-10 provides pressurizer design parameters.

The MPS3 pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all internal surfaces exposed to the reactor coolant.

The surge line nozzle and removable electric heaters are installed in the lower pressurizer head. The heaters are removable for maintenance or replacement. A thermal sleeve is provided to minimize stresses in the surge line nozzle. A retaining screen is located above the nozzle to prevent any foreign matter from entering the RCS. Baffles in the lower section of the pressurizer prevent an insurge of cold water from flowing directly to the steam/water interface and assist mixing.

Spray line nozzles, relief and safety valve connections are located in the upper head of the vessel. Spray flow is modulated by automatically-controlled air operated valves. The spray valves can be operated manually by a switch in the control room.

A small continuous spray flow is provided through a manual bypass valve around the power-operated spray valves to assure that the pressurizer liquid is homogeneous with the coolant and to prevent excessive cooling of the spray piping.

During an outsurge from the pressurizer, flashing of water to steam and generating of steam by automatic actuation of the heaters retain the pressure above the minimum allowable limit. During an insurge from the RCS, the spray system, which is fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves for normal design transients. Heaters are energized on high water level during insurge to heat the subcooled surge water that enters the pressurizer from the RC loop.

FSAR Section 5.4.14.1.4 states in part that the pressurizer is skirt-mounted to a ring girder which is suspended from the operating floor by four hanger columns. Four horizontal support restraints, which attach the ring girder to the building structure, prevent all motions except vertical translation and horizontal rotation. Integral lugs located on the pressurizer near the center of gravity fit into striker plate assemblies embedded in the concrete floor at elevation 51 ft. 4 in. These brackets allow thermal expansion of the pressurizer but resist horizontal and torsional displacements resulting from seismic and/or blowdown forces. The pressurizer support is shown on FSAR Figure 5.4 14. Refer to FSAR Table 5.4-18 for loading category, loading combinations, stress limits, and design code.

FSAR Section 3.9N discusses RCS design transients. FSAR Table 3.9N-1 summarizes RCS design transients. FSAR Table 5.2-1 indicates the pressurizer, surge line and RCS piping are all designed per the ASME B&PV Code, Section III, 1971 Edition through Summer 1973 Addenda. The ability of the pressure boundary components to perform throughout the design lifetime as defined in the design specification is confirmed by the stress analysis report required by the ASME Code, Section III.

The MPS3 pressurizer is tested and inspected per the requirements of Section XI of the ASME B&PV Code, 1989 Edition, no addenda.

NRC Bulletin 88-11 requested licensees to take certain actions to monitor thermal stratification in the pressurizer surge line because measurements indicate that top-to-bottom temperature in the surge line can reach 250°F to 300°F in certain modes of operation, particularly during heatup and cooldown. The generic evaluation of surge line stratification for the Westinghouse PWRs is included in WCAP-12639.

In a letter dated May 1, 1992, on behalf of MPS3, a plant-specific surge line analysis, together with the generic analysis (WCAP-12639), was submitted to the NRC to demonstrate compliance with NRC Bulletin 88-11. In a letter dated July 9, 1992, the NRC indicated that the plant-specific surge line analysis and WCAP-12639 have together demonstrated compliance with NRC Bulletin 88-11.

The MPS3 pressurizer and its supports were evaluated for continued acceptability regarding plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, documents the results of that review. NUREG-1838, Sections 2.3B.1.3 and 3.1B are applicable to the pressurizer. NUREG-1838 Sections 2.4B.3 and 3.5B are applicable to the pressurizer supports.

2.2.2.7.2 Technical Evaluation

2.2.2.7.2.1 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, in conjunction with the pressure control system components, keep the 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 the 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 sees maximum thermal gradients, and thus, experiences 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}. Therefore, if RCS pressure is high (T_{sat} is high) and T_{cold} is low, then the spray nozzle and upper shell also experience the maximum thermal gradients and thermal stresses.

An evaluation was performed in support of the MPS3 SPU to address the impact on the pressurizer and pressurizer supports. This evaluation was based on the range of NSSS operating parameters described in Section 1.1, Nuclear Steam Supply System Parameters to support an NSSS power level of 3666 MWt.

2.2.2.7.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The reactor vessel outlet (T_{hot}) and reactor vessel inlet (T_{cold}) temperatures from Section 1.1 define the normal operating temperatures for the surge and spray lines to the pressurizer. The reactor coolant pressure from Section 1.1 defines the pressurizer normal operating pressure (2250 psia). The saturated temperature corresponding to this pressure is 653ºF. The minimum values of T_{hot} and T_{cold} from all cases in Section 1.1 were used in the evaluation of the pressurizer.

The NSSS design transients discussed in Section 2.2.6, NSSS Design Transients, are applicable to the pressurizer. Additional information for the heatup and cooldown transients at the surge nozzle is obtained from the auxiliary system design transients.

The uprate parameters provided in Section 1.1 and the NSSS uprate design transients given in Section 2.2.6 provided the operating and transient conditions that were used in the SPU evaluations. A list of the NSSS design transients applicable to the MPS3 SPU, with their associated design value frequencies of occurrence are shown in Table 2.2.6-1. The transients listed and their associated frequencies of occurrence are unchanged from those in the current design basis list of transients. The design transients that were revised for the SPU are also noted in Table 2.2.6-1.

Assumptions

The Section 1.1 uprate parameters and Section 2.2.6, NSSS Design Transients uprate parameters are considered in the uprate evaluations. There are no changes due to the SPU (other than those indicated in Tables 1-1 and 2.2.6-1) to the pressure or thermal/hydraulic design parameters that would affect the pressurizer or its supports.

Unless indicated otherwise, the transients are assumed to be initiated with the pressurizer at the normal conditions for power operations, that is, saturation at 2250 psia. The water and steam volumes are assumed to be saturated liquid and saturated vapor, respectively, and the temperature is approximately 653°F.

Where pressurizer water temperature and/or steam temperature curves are not provided, these parameters are assumed to be the saturation temperature for the existing pressurizer pressure.

The relatively stagnant water normally in the spray piping is swept through the piping and into the pressurizer ahead of the spray flow from the cold leg. This water is assumed to be at 530°F. After the spray piping is swept out, the spray temperature is the same as the cold leg temperature.

Step temperature changes are assumed for components in contact with the spray and surge line insurges.

Seismic analyses and non-pressure boundary component evaluations are unaffected by the SPU.

Acceptance Criteria

The initial set of acceptance criteria for evaluating design inputs affecting the pressurizer stress reports by comparison with the design inputs considered in Section 1.1 and Section 2.2.6, were as follows:

- Hot and cold leg temperatures remain within the ranges of the operating temperatures that had previously been considered and justified in the pressurizer stress reports.
- NSSS design transients are less-than-or-equal-to the design transients previously considered in the pressurizer stress reports with regard to both severity and number of occurrences. Additionally, no new NSSS design transients that had not previously been considered were identified. The pressurizer temperature and pressure variations for each transient were considered in this comparison review to determine the relative severity of the revised design transients compared to the existing design transients.
- Design loads are less-than-or-equal in magnitude to the loads that were previously considered in the pressurizer stress reports with no changes to the load application points and number of occurrences.

If comparison of the design inputs for the MPS3 SPU with the pre-uprate design inputs reveals hot and/or cold leg temperatures, NSSS design transients or design loads that do not comply with the above criteria, then pressurizer structural analyses and evaluations will be performed, as necessary, to incorporate the revised design inputs. The acceptance criterion is that the MPS3 pressurizer components meet the stress/fatigue analysis requirements of the ASME Code, Section III (Reference 1) for the plant operation in accordance with the SPU.

The RCL piping loads on the pressurizer supports due to deadweight, thermal expansion, seismic OBE, and seismic SSE, LOCA and pipe break loading cases are obtained from the piping system analyses for the SPU program as described in Section 2.2.2.1, NSSS Piping, Components and Supports.

The acceptance criteria for the MPS3 RCL primary equipment pressurizer supports indicated in FSAR Section 3.9N3, Table 3.9N-4 and Table 5.4-18 are based on the B&PV, Section III, Subsection NF and Appendix F, 1974 Edition (Reference 2).

2.2.2.7.2.3 Description of Analyses and Evaluations

The analysis was performed by modifying results from the original MPS3 pressurizer stress reports, which were performed to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1971 Edition, Summer 1973 Addendum (Reference 1). Analytical models of various sections of the pressurizer were subjected to pressure loads, external loads (such as piping loads), and thermal transients.

The input parameters associated with the MPS3 SPU were reviewed and compared to the design inputs considered in the current pressurizer stress reports. In cases where revised input parameters are not obviously bounded, pressurizer structural analyses and evaluations were performed. An assessment of the potential impacts to the existing design basis analysis was performed via comparative analysis of the changes. This method involves a simplified engineering approach, using the existing analyses as the basis of the evaluation. Scaling factors were utilized to assess the impact of the changes relative to 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 1) to confirm that the ASME allowable limits are not exceeded.

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 each design transient in Section 2.2.6 was compared with the number for the corresponding transient in the current pressurizer design basis. The number and type of SPU transients are identical to those in the current design specification except that the heaters out-of-service and COMS transients were not included. Although the design specification refers to the COMS transient, MPS3 refers to the system for cold overpressure mitigation as the COPS.

Pressure fluctuations during the revised transients are the same or enveloped by the pressures in the original evaluations. It should be noted that the maximum pressure within each load category (normal, upset, emergency, faulted, and test) has not changed from the value used in the original evaluations. Thus, the revised transients have no effect on the primary stress evaluations performed previously for those categories. The above discussion shows that the differences in the pressure fluctuations are very small and do not have any significant effect on the stress analysis and fatigue evaluation of the pressurizer components that were originally analyzed.

The ΔT's between the pressurizer and the incoming T_{hot} and T_{cold} as well as the variation in the pressurizer steam temperature were determined for each of the normal and upset transients. Components affected by insurges at T_{hot} were the surge nozzle, lower head, heater well, support skirt, instrument nozzle, and immersion heater. Components affected by sprays at T_{cold} were the spray nozzle, upper head, upper shell, support lug, and the trunnion shell buildup. Components affected by the steam ΔT's were the safety and relief nozzles and the manway. Umbrella transients with various ΔT's were previously defined for each of these components. The transients were assigned to the appropriate component umbrella transients based on the values of the ΔT's. The stresses previously calculated were used, but the transient groupings and number of cycles differed from those used previously.

The pressurizer support loads from the piping system SPU analyses as described in Section 2.2.2.1, NSSS Piping, Components and Supports have been evaluated and remain within design basis limits.

SWOL were applied to the safe ends of the surge and safety and relief nozzles during the Spring 2007 outage. The effect of the SPU on those nozzle SWOLs has been addressed. The effects of the overlays on the existing stress and fatigue results for the nozzles were evaluated. The results of these calculations demonstrated that the weld overlays will have no significant effect on Section III stress and fatigue results of existing analyses performed per Section III of the ASME Code. It was concluded that the current Section III analysis of record remains applicable for the surge and safety and relief nozzles.

A structural weld overlay was applied to the safe end of the spray nozzle during the Fall 2005 outage. The effects of the overlay on the existing stress and fatigue results for the spray nozzle were evaluated. It was concluded that the pressurizer spray nozzle with the structural weld overlay would still meet the applicable ASME Code Section III requirements. That evaluation did not consider the effect of the SPU on the spray nozzle weld overlay. That has been addressed, and it has been concluded that consideration of the effect of the SPU on the spray nozzle weld overlay will not change the above conclusions.

The surge nozzle is subjected to thermal stratification pipe loads, and had been analyzed previously. The thermal stratification pipe loads were updated for the SPU Program.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed in Section 2.2.2.7.1, the pressurizer and supports are within the scope of License Renewal. The SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal boundaries. Operating the pressurizer at SPU conditions does not adversely affect RCPB integrity. Thus, no new aging effects requiring management are identified.

DNC has also evaluated the impact of the SPU on the conclusions reached in NUREG-1838 relative to pressurizer supports. The aging evaluations approved by the NRC in sections 2.4B.3 and 3.5B of NUREG-1838 for the pressurizer supports remain valid for the SPU conditions.

Therefore, the effects of the SPU do not impact the conclusions of the License Renewal SER.

2.2.2.7.2.4 Results

The analysis performed for SPU shows that the MPS3 SPU transients have a limited effect on the pressurizer components. Design, emergency, faulted and test condition stresses remain unchanged. The maximum primary-plus-secondary stress intensity ranges for normal and upset conditions also remain unchanged. Table 2.2.2.7.2-1 compares the fatigue usages calculated for the SPU with those reported in the original stress reports. The largest increases were for the instrument nozzle, where the fatigue usage increased from [ ]^{c,e}, and the shell at the trunnion buildup where the fatigue usage increased from [ ]^{c,e}

The maximum primary-plus-secondary stress intensity ranges of the pressurizer components are provided in Table 2.2.2.7.2-2.

All critical components of the MPS3 pressurizer were evaluated for operation at SPU conditions. It was determined that all ASME Code stress limits remain satisfied for all components, for all proposed operating conditions.

With respect to the supports, stresses for pressurizer components for SPU conditions were evaluated. In all cases, the stresses for all pressurizer components satisfy applicable acceptance criteria.

Also, the maximum increase in stress due to the stratification pipe loads revised for the SPU was found to be negligible compared to the pressure and thermal stresses and will have an insignificant impact on the surge line stratification analysis performed for the surge nozzle. Therefore, this evaluation concludes that the pressurizer maintains its ability to function as part of the primary pressure boundary.

2.2.2.7.3 Conclusion

DNC has reviewed the evaluation related to the structural integrity of pressure-retaining components and their supports. For the reasons set forth above, DNC concludes that the evaluation has adequately addressed the effects of the proposed SPU on these components and their supports. Based on the above, DNC further concludes that the evaluation has demonstrated that pressure-retaining components and their supports will continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

2.2.2.7.4 References

1. ASME Code, Section III, 1971 Edition with Addenda through Summer 1973.

2. ASME Code, Section III, Subsection NF and Appendix F, 1974 Edition.

Table 2.2.2.7.2-1 MPS3 Fatigue Usage Comparisons

Component	Revised Fatigue Usage	Previous Fatigue Usage
Surge Nozzle	[ ] c,e	[ ] c,e
Spray Nozzle	[ ] c,e	[ ] c,e
Safety and Relief Nozzles	[ ] c,e	[ ] c,e
Lower Head – Heater Penetrations	[ ] c,e	[ ] c,e
Heater Well	[ ] c,e	[ ] c,e
Upper Head and Shell	[ ] c,e	[ ] c,e
Support Skirt – Near Lower Head	[ ] c,e	[ ] c,e
Support Skirt - at Flange	[ ] c,e	[ ] c,e
Seismic Support Lug	[ ] c,e	[ ] c,e
Shell at Seismic Support Lug	[ ] c,e	[ ] c,e
Manway	[ ] c,e	[ ] c,e
Manway Bolt	[ ] c,e	[ ] c,e
Instrument Nozzle	[ ] c,e	[ ] c,e
Immersion Heater	[ ] c,e	[ ] c,e
Valve Support Bracket	[ ] c,e	[ ] c,e
Trunnion Buildup	[ ] c,e	[ ] c,e

Table 2.2.2.7.2-2 MPS3 Primary-Plus-Secondary Stress Intensity Ranges

Component	Calc/Allow *
Surge Nozzle	[ ] c,e
Spray Nozzle	[ ] c,e
Safety and Relief Nozzles	[ ] c,e
Lower Head – Heater Penetrations	[ ] c,e
Heater Well	[ ] c,e
Upper Head and Shell	[ ] c,e
Support Skirt – Near Lower Head	[ ] c,e
Support Skirt - at Flange	[ ] c,e
Seismic Support Lug	[ ] c,e
Shell at Seismic Support Lug	[ ] c,e
Manway	[ ] c,e
Manway Bolt	[ ] c,e
Instrument Nozzle	[ ] c,e
Immersion Heater	[ ] c,e
Valve Support Bracket	[ ] c,e
Trunnion Buildup	[ ] c,e

* Ratio of calculated to allowable stress intensity.

1. The 3Sm limit on the range of primary-plus-secondary stress intensity may be exceeded provided the rules of NB-3228.3 of the ASME Code are met. Those requirements have been satisfied for this component.

2.2.3 Reactor Pressure Vessel Internals and Core Supports

2.2.3.1 Regulatory Evaluation

RPV internals consist of all the structural and mechanical elements inside the reactor vessel, including core support structures. DNC reviewed the effects of the proposed SPU on the design input parameters and the design-basis loads and load combinations for the reactor internals for normal operation, upset, emergency, and faulted conditions. These include pressure differences and thermal effects for normal operation, transient pressure loads associated with LOCAs, and the identification of design transient occurrences. The DNC review covered the analyses of FIV for safety-related and non safety-related reactor internal components, as well as the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The DNC review also included a comparison of the resulting stresses and CUF against the corresponding Code-allowable limits. The acceptance criteria for this review are:

- 10 CFR 50.55a and GDC-1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed
- GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions
- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents
- GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences

Specific review criteria are contained in the SRP, Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5 and other guidance provided in Matrix 2 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800) and SRP Sections 3.9.1 (Rev. 2), 3.9.2 (Rev. 2), 3.9.3 (Rev. 1) and 3.9.5 (Rev. 2). As noted in the FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to:

- GDC-1 is described in the FSAR section 3.1.2.1. General Design Criterion1 - Quality Standards and Records.

  SSCs important to safety are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

Quality standards applicable to safety related SSCs are generally contained in codes such as the ASME Boiler and Pressure Vessel Code. The applicability of these codes is specifically identified throughout this report and is summarized in FSAR Section 3.2.5. FSAR Chapter 17 provides direct reference to the Quality Assurance Program established to provide assurance that safety related SSCs satisfactorily perform their intended safety functions. The procedures for generating and maintaining appropriate design, fabrication, erection, and testing records are contained within the referenced documents.

- GDC-2 is described in the FSAR Section 3.1.2.2, General Design Criterion 2 - Design Bases for Protection Against Natural Phenomena.

  Those features of plant facilities that are essential to the prevention of accidents that could affect the public health and safety or to the mitigation of accident consequences are designed to:

  1. Quality standards that reflect the importance of the function to be performed. Approved design codes are used when appropriate to the nuclear application.

  2. Performance standards that enable the facility to withstand, without loss of the capability to protect the public, the additional forces imposed by the most severe earthquake, flooding condition, wind, ice, or other natural phenomena for the site, and credible combinations of the effects of normal and accident conditions with the effects of the natural phenomena.

  Features of the facility essential to accident prevention and mitigation of accident consequences, which are designed to withstand the effects of natural phenomena, are:

  1. The reactor coolant pressure boundary and containment barriers

  2. The controls and emergency cooling systems whose functions are to maintain the integrity of these barriers

  3. Reactivity systems, monitoring systems, and fuel systems

  All piping, components, and supporting structures of the reactor and safety related systems are designed to withstand a specified seismic disturbance and credible combinations of effects of normal and accident conditions coincident with the effects of natural phenomena. Plant design criteria specify that there is to be no loss of function of such equipment in the event of the SSE ground acceleration acting in the horizontal and vertical directions simultaneously. The dynamic response of Seismic Category I structures to ground acceleration, based on an envelope of characteristics of the site foundation soils and on the critical damping of the foundation and structures, is included in the design analysis.

  Unit design criteria which ensure protection against natural phenomena are described in FSAR Section 3.2 (Classification of SSCs), FSAR Section 3.3 (Wind and Tornado Loadings), FSAR Section 3.4 (Water Level Design), and FSAR Section 3.7 (Seismic Design).

- GDC-4 is described in the FSAR Section 3.1.2.4, Environmental and Missile Design Bases.

  SSCs important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCA's. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

  SSCs important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

  FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the SSCs important to safety are designed.

- GDC-10 is described in the FSAR Section 3.1.2.10, Reactor Design.

  The reactor core and associated coolant, control, and protection systems are designed with adequate margins to:

  1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These are within the capability of the plant cleanup system and are consistent with plant design bases.

  2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

  3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

  Note that fuel damage as used under Item 1 is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3.

  FSAR Chapter 4 discusses the design bases and design evaluation of reactor components.

FSAR Section 3.9N.5.3 discusses design loadings for the RVI. It states in part that

- The combination of design loadings fit into the normal, upset, emergency or faulted conditions as defined in the ASME Code, Section III.

- Loads and deflections imposed on components due to shock and vibration are determined analytically and experimentally in both scaled models and operating reactors. The cyclic stresses due to these dynamic loads and deflections are combined with the stresses imposed by loads from components weights, hydraulic forces and thermal gradients for the determination of the total stresses of the internals.

- The reactor internals are designed to withstand stresses originating from various operating conditions as summarized in FSAR Table 3.9N-1.

FSAR Section 3.9N.2.3 describes the modeling and analyses performed for dynamic response analysis of reactor internals under operational flow transients and steady state conditions.

FSAR Section 5.2.3.1 states in part that typical material specifications used for reactor vessel internals required for ECC, for any mode of normal operation or under postulated accident conditions, and for core structural load bearing members are listed in FSAR Table 5.2-3.

The RPV internals and core supports were evaluated for continued acceptability to support plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.3B.1.2 and 3.1B are applicable to the RPV internals and core supports.

NUREG 1838, Appendix A, Commitments for License Renewal of MPS Unit 3, Items 13 and 14, present commitments concerning license renewal regarding the RVI and the core barrel.

2.2.3.2 Technical Evaluation

2.2.3.2.1 Introduction

The RPV internal system consists of the reactor vessel, reactor internals, fuel, and CRDMs. The reactor internals functional description is provided in the following text. The reactor internals are designed to withstand forces due to normal, upset, emergency, and faulted conditions.

Changes in the primary coolant system operating conditions (e.g., increase in power) also produce changes in the boundary conditions; this includes loads and temperatures experienced by the reactor internals structures or components. Ultimately, this results in changes in the stress levels in these components and changes in the relative displacement between the reactor vessel and the reactor internals. To ensure that the reactor internal components maintain their design functions, and to ensure safety questions have been reviewed, a systematic evaluation of the reactor components has been performed to assess the impact of increased core power on the reactor internal components. The reactor internal core support components are classified as follows:

Upper Core Support Assembly (comprised of the following individual components)

- Upper support plate
- Upper core plate
- Upper core plate fuel pins
- Upper support column

Lower Core Support Assembly (comprised of the following individual components)

- Lower support plate
- Lower core plate
- Lower core plate fuel pin
- Lower support column
- Core barrel assembly
- Baffle former assembly
- Radial keys and clevis insert assembly
- Upper core plate alignment pin

The internal structures are defined as all structures within the reactor vessel that are not core support structures, fuel assemblies, control assemblies, or instrumentation. These structures are attached to and supported by the core support structures.

Reactor Internals Functional Description

The reactor internals core support structures are within the confines of the reactor vessel. The function of the structure is to provide the direct support and restraint of the core, i.e., fuel assemblies. In addition, the total structure, which includes internal structures, should provide the following:

- The orientation of the reactor core.
- The orientation, guidance, and protection of the reactor control rod assemblies.
- A passageway for directional and metered control of the reactor coolant flow through the reactor core.
- A passageway, support, and protection for any in-vessel or in-core instrumentation.
- A secondary core support for limiting the downward displacement of the core support structure in the event of a postulated failure of the core-barrel subassembly.
- Reactor vessel neutron shielding.

Function of Core Support Structures

Upper Core Support Assembly

The upper core support assembly provides the vertical and lateral restraint and lateral alignment to the top of the core through its primary components (the upper support subassembly, support columns, and the upper core plate) and its interface with the reactor vessel. The assembly also provides the support for the internal structures, such as the instrumentation conduit and supports, and reactor control rod guide tubes.

The upper support subassembly, which is supported on the outer edges, transfers the loading of the upper core support assembly to the reactor vessel. Keyways, with customized inserts to maintain required gaps, are located in the outer edges of the subassembly to provide the upper-core-support-assembly to reactor vessel to lower-core-support assembly alignment, and to limit any transverse or rotational movement of the subassembly. There are penetrations through the subassembly for spray nozzles that allow limited flow into the reactor vessel upper head region.

The support columns transfer vertical and lateral loads to the upper support subassembly and support the upper core plate vertically. Guides are provided at the lower end of the columns for coolant flow.

The upper core plate, which is attached to the bottom of the upper support columns, forms the upper periphery of the core, transfers core loading to the support columns, and, when in place within the reactor vessel, rests on the fuel assembly springs causing the core preload. The plate is perforated to allow coolant flow while maintaining a uniform velocity profile. The underside of the plate contains the upper fuel pins, which engage the top of the fuel assemblies. The upper-core-periphery to lower-core-periphery alignment is provided through keyways in the outer edges of the plate that contain customized inserts that provide the required pin engagement gaps. In addition, the keyway/insert system limits any rotation or translation of the upper core plate.

Lower Core Support Assembly

The lower core support assembly is the major supporting assembly of the total structure. The assembly functions are as follows:

- Support the core and the attached internal structures
- Transfer these and other design loadings to the reactor vessel
- Provide the restraint and alignment of the core
- Provide the directional and metered control of the reactor coolant flow through the core
- Provide neutron shielding for the reactor vessel

Fuel assemblies are placed into the core-barrel subassembly and rest on the lower core plate. The lower core plate is supported on the lower core barrel ledge and by the lower support columns, and contains the lower fuel pins that provide location and alignment for the bottom of the fuel assemblies. The lower core plate is perforated to allow directional and metered control of flow of the reactor coolant and is attached to the core barrel and the flange, forming the core barrel subassembly. The function of the core barrel subassembly is to transmit the loading to the reactor vessel. This is accomplished by the core-barrel flange, which rests on a ledge provided on the reactor vessel and limited loading is transmitted at the bottom by the radial support system.

The radial support system consists of keys that are attached to the lower end of the core-barrel subassembly on the lower support plate and that engage clevises provided in the reactor vessel. This system restricts the lower end of the core-barrel subassembly from rotational or tangential movement, but allows for radial thermal growth and axial displacement.

Inside the core barrel, above the lower supporting component, is the baffle assembly. This subassembly forms a radial periphery of the core and, through the dimensional control of the cavity, i.e., the gap between the fuel assemblies and baffle plates, provides directional and metered control of the reactor coolant through the core.

2.2.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The principal input parameters utilized in the analysis of the reactor internal components and RPV system are the RCS design parameters provided in Licensing Report, Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1. For structural analysis/evaluations, the NSSS design transients discussed in Section 2.2.6, NSSS Design Transients were considered. The fuel considered is a full core of Westinghouse 17x17 Robust Fuel Assembly (RFA-2) with intermediate flow mixer (IFM) grids with and without the thimble plugging devices installed.

Acceptance Criteria

- The design core bypass flow limit with the thimble plugging devices installed is 6.6 percent of the total vessel flow rate and is 8.6 percent with the thimble plugging devices removed.
- The RCCA drop time Technical Specification of 2.7 seconds is to be maintained.
- For the structural and fatigue evaluations of core support components, the components stresses meet the allowable stress limits and the cumulative fatigue usage factors must be less than 1.0.

2.2.3.2.3 Description of Analyses and Evaluations

The RVI have been analyzed for the MPS3 SPU revised design parameters and the design basis load combinations. The analysis of the components was performed for the normal, upset, emergency and faulted conditions (LOCA/Seismic).

The methodology and code for the SPU reactor pressure vessel system dynamic analyses (LOCA and seismic) is different than what is used in the MPS3 current design basis. The SPU reactor pressure vessel system dynamic analyses are performed with a three-dimensional nonlinear finite element model which represents the dynamic characteristics of the reactor vessel and its internals in the six geometric degrees of freedom. Approval of this type of mathematical modeling is contained in Reference 1. The ANSYS code is used to perform reactor pressure vessel system LOCA and seismic dynamic analyses for the SPU. ANSYS was applied and approved by the NRC in the recently completed Westinghouse WOG Baffle Bolting Program (Reference 2). The analyses comply with any limitations, restrictions, and conditions specified in the approving safety evaluations.

The results of these analyses confirm that there is no adverse impact on the structural adequacy of the reactor internals components for the SPU conditions.

Thermal-Hydraulic System Evaluations

System Pressure Losses

The principal RCS flow route through the RPV system at MPS3 begins at the 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 support 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 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 considered 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.

Thermal hydraulic evaluations were performed by solving the mass and energy balances for the reactor internals fluid system. These analyses determined the distribution of pressure and flow within the reactor vessel, reactor internals, and the reactor core. Results were obtained with a full core of Westinghouse 17x17 RFA-2 fuel with IFM grids with and without the thimble plugging devices installed, and at RCS conditions, as given in Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1.

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. Variations in the size of some of the bypass flow paths, such as gaps at the outlet nozzles and the core cavity, occur during manufacturing or change due to fuel assembly changes. Plant-specific, as-built dimensions are used in order to demonstrate that the core bypass flow limits are not violated. Therefore, analyses are performed to estimate core bypass flow values to either show that the design bypass flow limit for the plant are not exceeded or to determine a revised design core bypass flow.

Fuel assembly hydraulic characteristics and system parameters, such as inlet temperature, reactor coolant pressure, and flow were used to determine the impact of SPU RCS conditions on the total core bypass flow. The results of this analysis calculated a core bypass flow value of 5.67 percent with the thimble plugging devices installed and 7.59 percent with thimble plugging devices removed. Therefore, the design core bypass flow value of 6.6 percent with thimble plugging devices installed and 8.6 with thimble plugging devices removed remains acceptable.

Hydraulic Lift Forces

An evaluation was performed to estimate hydraulic lift forces on the various reactor internal components for the SPU parameters shown in Section 1.1, Nuclear Steam Supply System Parameters, Table 1.1. This is done to show that the reactor internals assembly would remain seated and stable for all conditions. Based on the evaluation performed for the MPS3 SPU, the reactor lower internals remain seated and stable for the following SPU, RCS conditions:

- Hot full-power normal conditions

- Cold zero-power normal conditions
- Seismic OBE with hot full-flow upset conditions
- Hot pump overspeed (HPO) upset conditions (without OBE)

In addition, a minimum of 100,000-pound hold-down force is maintained during normal operating conditions. These evaluations conservatively assume that no internals hold-down contribution is provided by the fuel assemblies. For HPO with OBE upset conditions, the lower internals lift off the vessel ledge assuming that all the fuel assemblies lift-off. The lift-off of the lower internals due to HPO with OBE is not considered to be a safety concern.

Upper Head Fluid Temperatures

The average temperature of the primary coolant fluid that occupies the reactor vessel closure head (RVCH) volume is an important initial condition for certain dynamic LOCA analyses. Therefore, it was necessary to determine the upper head temperature when changes in the RCS conditions take place in the plant. Determination of upper head temperature stemmed from the Thermal Hydraulic Reactor Internals Vessel Evaluation (THRIVE) calculations used to assess the core bypass flow. THRIVE models the interaction between all different flow paths into and out of the closure head region. Based on this interaction, it calculates the core bypass flow into the head region and the average head fluid temperature for different flow path conditions. MPS3 is designed such that the upper head region is at T_{cold} and at SPU conditions the calculated upper head region average fluid temperature remained at $T_{cold.}$ These upper head fluid temperatures were provided as inputs and were used in subsequent LOCA analyses.

RCCA Scram Performance Evaluation

The RCCAs represent a critical interface between the fuel assemblies and the other internal components. It is imperative to show that the SPU RCS conditions do not adversely impact the operation of the RCCAs, either during accident conditions or normal operation.

The analysis performed determined the potential impact of the conditions shown in Licensing Report Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1 on the limiting RCCA drop time. The maximum estimated RCCA drop time was calculated to be 2.26 seconds to the top of dashpot, which is still less than the current Technical Specification limit of 2.7 seconds.

Mechanical System Evaluations

LOCA Loads

To perform the RPV LOCA analyses of MPS3, a finite element model of the RPV system was developed. The mathematical 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. For the MPS3 SPU, LOCA analyses were performed to generate core plate motions and the reactor vessel/internals interface loads.

The results of LOCA reactor vessel displacements and the impact forces calculated at vessel/internals interfaces are used to evaluate the structural integrity of the reactor vessel and its internals. The core plate motions were used in the fuel grid crush analysis and to confirm the structural integrity of the fuel as discussed in detail in Section 2.8.1, Fuel System Design.

Seismic Analyses

The SPU does not impact the seismic response of the reactor internals; therefore, the nonlinear time-history seismic analysis of the RPV system was not performed.

Flow-Induced Vibrations

Flow-induced vibrations of pressurized water reactor internals have been studied for a number of years. The objective of these studies is to show the structural integrity and reliability of reactor internal components. These efforts have included in-plant tests, scale-model tests, as well as tests in fabricators' shops and bench tests of components, and various analytical investigations. The results of these scale-model and in-plant tests indicate that the vibrational behavior of two-, three-, and four-loop plants is essentially similar, and the results obtained from each of the tests compliment one another and allow a better understanding of the FIV phenomena. Based on the analysis performed for MPS3, reactor internals response due to FIV is extremely small and well within the allowable based on the high cycle endurance limit for the material. The results of FIV analyses for the MPS3 SPU are provided in Table 2.2.3-1 and Table 2.2.3-2.

Evaluation of Reactor Internal and Core Support Structure Components

In addition to supporting the core, a secondary function of the RVI assembly is to direct coolant flows within the vessel. While directing primary flow through the core, the internals assembly also establishes secondary flow paths for cooling the upper regions of the reactor vessel and 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 flow rate required to remove heat generated within the structural components due to radiation (for example, gamma heating). The configuration of the internals provides 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.

The MPS3 reactor internals were designed and built prior to the implementation of Subsection NG of the ASME Boiler and Pressure Vessel Code; therefore, a plant-specific stress report on the reactor internals was not required. The structural integrity of the MPS3 reactor internals design has been ensured by analyses performed on both generic and plant-specific bases to meet the intent of the ASME Code. These analyses were used as the basis for evaluating critical MPS3 reactor internal components for SPU RCS conditions and revised NSSS design transients.

Structural evaluations demonstrate that the structural integrity of reactor internal components is not adversely affected either directly by the SPU RCS conditions and NSSS design transients, or by secondary effects on reactor thermal-hydraulic or structural performance. Heat generated in reactor internal components, along with the various fluid temperature changes, results in thermal gradients within and between components. These thermal gradients result in thermal stresses and thermal growth, which must be considered in the design and analysis of the various components.

Component Evaluations

A series of evaluations for the MPS3 were performed on reactor internal components for the SPU conditions. The most limiting reactor internal components that were evaluated are as follows:

- Upper core plate
- Lower support plate
- Lower core plate
- Lower support column
- Core barrel
- Baffle-former bolts

The results of these evaluations demonstrate that the above listed components are structurally adequate for the SPU conditions and the fatigue usage factors were less than 1.0. Since the skin stress range factor does not significantly increase for each component and the most limiting components qualify, the remaining core support components qualify as well. A summary of stresses versus allowable and corresponding fatigue usage factors is given in Table 2.2.3-3.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the RVI components. This licensing report section addresses the maximum stress intensity ranges and cumulative fatigue damage for critical RVI components considering the impact of SPU conditions on license renewal and evaluates those ranges and fatigue damage against the ASME code limits. SCC of RVI components is addressed in Section 2.1.5, Reactor Coolant Pressure Boundary Materials.

The evaluations (summarized in this section) of maximum stress intensity ranges and cumulative fatigue usage factors for the limiting core support components of the RVI, considering SPU conditions, show that the reactor vessel core support components continue to meet the ASME acceptable limits. Since the original 40-year design transient set has been shown to be bounding for 60 years of operation based on the finding that the number of original design cycles bounds the actual plant cycles, and the number of design cycles for the SPU has not changed from the original 40-year transient set, the fatigue evaluations of the RVI components are valid for 60 years of operation.

The current ASME Section XI Inservice Inspection Program is considered to provide reasonable assurance that aging effects are managed such that the intended functions of RVI components are maintained during the license renewal period. The NRC staff concluded that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of structure and components subject to an aging management review such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the current licensing basis, as required by 10 CFR 54.29 (a).

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the RVI. The aging evaluations approved by the NRC in NUREG-1838 for the RVI components remain valid for SPU conditions.

2.2.3.2.4 Results

Analyses have been performed to assess the effect of changes due to the SPU at MPS3. The various results reached are as follows:

- The design core bypass flow value of 6.6 percent and 8.6 percent of the total vessel flow with and without thimble plugging devices installed respectively is maintained for the SPU conditions.
- An RCCA performance evaluation was completed and the results indicated that the current 2.7-second RCCA drop-time-to-dashpot entry limit (from gripper release of the drive rod) is satisfied at the SPU conditions.
- Evaluations of the limiting reactor internal core support components were performed, which indicated that the structural integrity of the reactor internals is maintained at the SPU conditions and the cumulative fatigue usage factors were all shown to be less than 1.0.

The results of component structural analyses are summarized in Table 2.2.3-3.

2.2.3.3 Conclusion

DNC has reviewed the evaluations related to the structural integrity of reactor internals and core supports and concludes that the evaluations have adequately addressed the effects of the proposed SPU on the reactor internals and core supports. DNC further concludes that the evaluations have demonstrated that the reactor internals and core supports will continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, and GDC-10 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the design of the reactor internal and core supports.

2.2.3.4 References

1. WCAP-9401-P-A, “Verification Testing and Analysis of the 17x17 Optimized Fuel Assembly,” August 1981.

2. WCAP-15029-P-A, Revision 1, “Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distribution Under Faulted Load Conditions,” December 1998.

Table 2.2.3-1 Lower Internal Critical Component Stresses Due to FIV

Component	Maximum Alternating Stress (psi)	ASME Code Endurance Limit (1) (high-cycle fatigue) (psi)
Core Barrel Flange	[ ]a,c	23,700
Core Barrel Girth Weld	[ ]a,c	23,700
Note: 1. Basis is ASME Code section NB-3222 and Figure I-9.2.2, Curve A and Table I-9.2.2.		

Table 2.2.3-2 Upper Internal Critical Component Strains Due to FIV

Component	Uprate Mean Strain in/in $\times 10^{-6}$	Endurance Limit Strain in/in $\times 10^{-6}$
Guide Tubes	[ ] a,c	101.5

Table 2.2.3-3 Reactor Internal Components Stresses and Fatigue Usage Factors

Component	Stress Intensity (ksi) S.I. = ($P_m + P_b + Q$)	Allowable S.I. ($3\ S_m$) ksi	Fatigue Usage
Upper Core Plate	[ ] a,c	48.6	[ ] a,c
Lower Support Plate	[ ] a,c	48.3	[ ] a,c
Lower Core Plate	[ ] a,c	48.6	[ ] a,c
Lower Support Columns	[ ] a,c	48.3	[ ] a,c
Core Barrel Outlet Nozzle: Section A-A Section B-B	[ ] a,c [ ] a,c	34.4 49.2	[ ] a,c [ ] a,c
Baffle-Former Bolts(2)	—	—	—

Notes:
1. Exceeded 3 S_m limit, simplified elastic-plastic analysis was performed to calculate fatigue strength, as allowed by ASME, B&PV Code, Section III, NB 3228.5. These conditions have been met and the fatigue usage is less than 1.0.
2. The basis of the baffle-former bolt qualification is a fatigue test. The evaluation of the revised loads consisted of demonstrating that the loads associated with SPU are acceptable for the plant design life. Therefore, it is concluded that the baffle-former bolts are structurally adequate for the SPU RCS conditions.

2.2.4 Safety-Related Valves and Pumps

2.2.4.1 Regulatory Evaluation

DNC's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME B&PV Code and within the scope of Section XI of the ASME B&PV Code and the ASME Operations and Maintenance (O&M) Code, as applicable. The DNC review focused on the effects of the proposed SPU on the required functional performance of the valves and pumps. The review also covered any impacts that the proposed SPU may have on the motor-operated valve (MOV) programs related to GL 89-10, GL 96-05, and GL 95-07. Lessons learned from the MOV Program and the application of those lessons learned to other safety-related power-operated valves were also evaluated.

The acceptance criteria for safety-related valves and pumps are based on:

- GDC-1, insofar as it requires that structures, systems, and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.
- GDC-37, GDC-40, GDC-43, and GDC-46, insofar as they require that the ECCS, the containment heat removal system, the containment atmospheric cleanup systems, and the cooling water system, respectively, be designed to permit appropriate periodic testing to ensure the leak-tight integrity and performance of their active components.
- GDC-54, insofar as it requires that piping systems penetrating containment be designed with the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits.
- 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section must meet the inservice testing program requirements identified in that section.

Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6, and guidance is provided in Matrix 2 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 3.9.6, Rev. 2.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 Station design relative to conformance to:

- GDC-1 is described in FSAR Section 3.1.2.1, Quality Standards and Records (Criterion 1)

  Structures, systems, and components important to safety are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

Quality standards applicable to safety related structures, systems, and components are generally contained in codes such as the ASME Boiler and Pressure Vessel Code. The applicability of these codes is specifically identified throughout this report and is summarized in the FSAR Section 3.2.5. FSAR Chapter 17 provides direct reference to the Quality Assurance Program established to provide assurance that safety related structures, systems, and components satisfactorily perform their intended safety functions. The procedures for generating and maintaining appropriate design, fabrication, erection, and testing records are contained within the reference documents.

- GDC-37 is described in FSAR Section 3.1.2.37, Testing of Emergency Core Cooling System (Criterion 37)

  Active components of the emergency core cooling system can be actuated from the emergency power source at any time during unit operation to demonstrate operability. Tests are performed during refueling shutdowns to demonstrate proper automatic operation of the emergency core cooling system. An integrated system test is performed. FSAR Sections 6.3 and 7.3 describe the above tests.

- GDC-40 is described in FSAR Section 3.1.2.40, Testing of Containment Heat Removal System (Criterion 40)

  The design of the containment depressurization systems permits periodic pressure and functional testing, as described in FSAR Section 6.2.2.4.

- GDC-43 is described in FSAR Section 3.1.2.43, Testing of Containment Atmosphere Cleanup Systems (Criterion 43)

  The design of the supplementary leak collection and release system permits periodic pressure and functional testing of components, as described in FSAR Section 6.5.1.4.

- GDC-46 is described in FSAR Section 3.1.2.46, Testing of Cooling Water System (Criterion 46)

  The service water system (FSAR Section 9.2.1), reactor plant component cooling water system (FSAR Section 9.2.2.1), charging pumps cooling system (FSAR Section 9.2.2.4), safety injection pumps cooling system (FSAR Section 9.2.2.5), and the spent fuel pool cooling and purification system (FSAR Section 9.1.3) are designed to permit periodic pressure and functional testing. With the exception of the safety injection pumps cooling system, these systems operate during normal operation and shutdown; thus, the structural and leaktight integrity of the system components, the operability and performance of most of the active components, and the operability of the system as a whole are continuously demonstrated. The active components that cannot be tested during normal system operation are tested during shutdown.

  The safety injection pumps cooling system, which is not normally in service, is periodically tested to assure structural and leaktight integrity of its components, the operability and performance of its active components, and the operability of the system as a whole.

  The performance of the full operational sequence for the safety related portions of the above systems that brings each system into operation for reactor shutdown, LOCA, or loss of unit power is evaluated periodically in conjunction with the applicable portions of the protection system.

Transfer between normal and emergency power sources is discussed in FSAR Section 8.3.

- GDC-54 is described in FSAR Section 3.1.2.54, Testing of Cooling Water System (Criterion 54)

  The piping systems penetrating the containment structure are designed to minimize leakage. Containment isolation valves provide the capability to seal most penetrations redundantly; FSAR Section 6.2.4 describes the few exceptions in detail. Pressure taps provide the capability to perform a Type C (10 CFR 50 Appendix J) test to measure containment isolation valve leakage rates, as outlined in FSAR Section 6.2.4.

FSAR Tables 1.9-1 and 1.9-2 document compliance with SRP Section 5.2.1.1, Rev. 2, which addresses 10 CFR 50.55a. These tables identify differences between the MPS3 design and the requirements of 10 CFR 50.55a. No differences between the MPS3 design and the requirements of 10 CFR 50.55a(f) are identified.

As addressed in FSAR Section 3.9.6, a test program, designated the MPS3 IST Program, has been developed to ensure that all safety-related pumps and valves will be in a state of operational readiness throughout plant life. The ASME Code, Section XI, 1980 Edition through Winter 1980 Addendum, provided the basic requirements to identify applicable pumps and valves and to develop test requirements. The program follows the guidance of Generic Letter 89-04, “Guidance on Developing Acceptable Inservice Testing Programs,” and NUREG-1482, “Guidelines for Inservice Testing at Nuclear Power Plants.”

FSAR Section 3.9.6.1 states in-part that IST is required for all Class 1, 2, and 3 pumps (both centrifugal and displacement types) that are provided with an emergency power source. Drivers are excluded except when the pump and driver form an integral unit and the pump bearings are in the driver. Tests and examination procedures required by ASME XI Subsection IWP are defined in the MPS3 IST Program and are performed by DNC. FSAR Section 3.9.6.2 identifies the following categories of valves that are subject to inservice testing:

- Category A - Valves for which seat leakage is limited to a specific maximum amount in the closed position for fulfillment of their function.
- Category B - Valves for which seat leakage in the closed position is inconsequential for fulfillment of their function.
- Category C - Valves which are self-actuating in response to some system characteristic, such as pressure (relief valves) or flow direction (check valves).
- Category D - Valves which are actuated by an energy source capable of only one operation, such as rupture disks or explosive actuated valves.
- Category E - Valves which are normally locked (or sealed) open or locked (or sealed) closed to fulfill their function.

Tests and examination procedures required by ASME XI Subsection IWV are defined in the MPS3 IST Program and are performed by DNC.

Technical Specification surveillance requirements for inservice testing of ASME Code Class 1, 2, and 3 components are addressed in TS 4.0.5.

MPS3 TS 4.0.5 addresses surveillance requirements for inservice testing of ASME Code Class 1, 2, and 3 components.

The NRC acceptance of the MPS3 MOV Program (GL 89-10) is documented in a letter dated May 14, 1998.

In NRC letter to NNECO, "Completion of Licensing Activity on Northeast Nuclear Energy Company Response to Generic Letter 96-05, Millstone Nuclear Power Station, Unit 3," June 9, 2000, the NRC attached the Safety Evaluation for MPS3's response to GL 96-05, and stated that NNECO had established an acceptable program to periodically verify the design–basis capability of the safety-related MOVs at MPS3 through its commitment to all three phases of the Joint Owners Group (JOG) Program on MOV Periodic Verification, and was adequately addressing the actions requested in GL 96-05. In the NRC letter, "Final Safety Evaluation on Joint Owners Group Program on Motor-Operated Valve Periodic Verification," September 25, 2006, the NRC concluded that the JOG Program provided an acceptable industry-wide response to GL 96-05 for valve age-related degradation where implemented in accordance with the Safety Evaluation.

In a letter dated January 13, 1998, the NRC documented their acceptance of the MPS3 actions related to pressure locking and thermal binding of safety-related power-operated gate valves (GL 95-07).

Plant programs credited for aging management were evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review.

The Millstone Station "Closed-Cycle Cooling Water Systems" Program is addressed in License Renewal SER Section 3.0.3.2.4, and is described in the DNC Technical Report, "Closed-Cycle Cooling Water Systems, Millstone Power Station." As identified in these documents, surveillance testing of the following pumps per the IST Program is included in the "Closed-Cycle Cooling Water Systems" Program to monitor component performance for the detection of degradation prior to loss of intended function: reactor plant component cooling water pumps, control building chilled water pumps, charging pump seal cooling pumps, and the safety injection pump cooling pumps.

Safety-related valves are addressed within the SER under the systems that contain them.

2.2.4.2 Technical Evaluation

2.2.4.2.1 Introduction

MPS3 IST Program

As discussed in the Millstone Station Program Description, "Inservice Test Program," and the Millstone Station "IST Program Manual," the objective of the IST Program is to ensure that all components classified as ASME Code Class 1, 2, or 3 which are required to perform credited safety function, as defined in the licensing basis and are within the IST scope, are tested in accordance with the applicable requirements of the ASME B&PV Code, Section XI, and/or the ASME/ANSI OM Code as specified in 10 CFR 50.55a.

The “MPS3 Inservice Testing Program Plan” describes the IST Program for verifying the operational readiness of Class 1, 2, and 3 pumps and valves and their actuating and position indicating systems. As identified in the “MPS3 Inservice Testing Program Plan,” the IST Program defined in this Plan is applicable from February 7, 1998, to February 6, 2008. The “MPS3 Inservice Testing Program Plan” includes an IST Valve Test List and an IST Pump Test List which effectively defines the scope of the program.

The “MPS3 Pump and Valve Inservice Testing Basis Document” provides the basis for inclusion or exclusion of certain Class 1, 2, and 3 pumps and valves, documents the component-specific test requirements, and documents current NRC approved Relief Requests. Testing of pumps within the scope of the IST Program is based on the requirements of ASME/ANSI OM-6, 1987 Edition through 1988 Addenda. Testing of valves (except check valves) within the scope of the IST Program is based on the requirements of ASME/ANSI OM-1 and OM-10, 1987 Edition through 1988 Addenda. Check valves within the scope of the IST Program are tested in accordance with the ASME OM Code, 1995 Edition, OMa-1996 Addenda.

Certain valves which are exempt from testing under OM-10, but are important to safety, are included as augmented testing. These valves are specifically identified as not required by the ASME Codes. (Note: Augmented testing of certain valves within the scope of the IST Program may also be performed [e.g., performance of stroke time testing of a valve in both directions, when testing in one direction only is required].) Valves which meet the following criterion and are not part of the IST Program may be included in a Supplemental Test Program: active and passive valves whose failure would have a significant impact on unit availability and where IST requirements can be reasonably satisfied.

The IST Program implements pump and valve surveillance testing requirements identified in the Technical Specifications.

MPS3 MOV Program

The technical requirements for implementation of the MOV Program at Millstone are contained in the “Millstone MOV Program Manual.” The MPS3 MOV Program implements the recommendations and requirements of GL 89-10, GL 96-05, and GL 95-07. Generic Letter 89-10 requested that licensees develop a comprehensive program to ensure MOVs in safety-related systems will operate under design basis conditions. Generic Letter 96-05 requested licensees to develop programs for periodic verification of design basis capability of safety-related MOVs. Generic Letter 95-07 requested that licensees take actions to ensure that safety-related power-operated gate valves that are susceptible to pressure locking or thermal binding are capable of performing their safety functions.

All active safety-related MOVs in safety-related piping systems are included in the MOV Program.

A system and functional design basis review calculation is performed for each MOV within the scope of GL 89-10. System parameters identified/documented in the system level review include the following for both open and closed valve strokes:

- Upstream and downstream line pressures
- Maximum differential pressure
- Fluid flow rate
- Fluid temperature

The results of the system and functional design basis review calculations are used as inputs in the calculations which determine MOV thrust and torque values. The EPRI MOV Performance Prediction methodology (PPM) is used in the determination of the thrust/torque values for a majority of MOVs in the MOV Program.

MPS3 calculation, "MP3 MOV Preventative Maintenance and Periodic Verification Requirements," documents the implementation plan for compliance with the requirements of GL 96-05 and related NRC commitments. This calculation identifies the safety-related MOVs included in the GL 96-05 program, and also identifies the risk category (i.e., high, medium, low) of the MOVs in the program.

MPS3 calculation, "MOV Pressure Locking and Thermal Binding – PI-20 Evaluation," documents the pressure locking / thermal binding susceptibility evaluations for motor-operated gate valves, in conformance with GL 95-07.

The MOV motor capability torque under elevated ambient temperature and degraded voltage conditions is a function of (1) derated motor torque at elevated ambient temperature, and (2) the available voltage at the motor terminals under the worst case accident scenario. The MOV motor capability torque values under elevated ambient temperature and degraded voltage conditions are determined in the MOV thrust/torque calculations.

Supplement 1 to NRC Information Notice 96-48, Motor-Operated Valve Performance Issues," addressed guidance from the Limitorque Corporation (Limitorque Technical Update 98-01) for predicting torque output capability from its AC-powered motor actuators used to open and close MOVs. The requirements of Limitorque Technical Update 98-01 have been incorporated into the Millstone calculation that addresses determination of thrust/torque values. This calculation also incorporates the guidelines of Limitorque Technical Update 93-03, which addresses effects of elevated temperature on ac-powered motor starting torque.

MPS3 AOV Program

MPS3 has in place an AOV Program for testing, inspection, and maintenance of AOVs. The Millstone Station Program Description, "Air Operated Valve Program," identifies the program scope and applicability, responsibilities, and key elements. The program is considered dynamic in nature to allow for enhancements and modifications based on experience gained from station testing, station and industry experience, and current industry information.

The following categories are used for AOV categorization; valves that do not meet any of the following categories are considered "Out of Scope" of the AOV Program:

- Category 1: AOVs in Maintenance Rule systems that are active and support High Safety Significant Functions, whether they are safety-related or not.
- Category 2: AOVs in Maintenance Rule systems that are safety-related and active, and support Medium Safety Significant or Low Safety Significant Functions.
- Category 3: AOVs in Maintenance Rule systems that do not meet the requirements of Categories 1 and 2. Valves in this group would be active, nonsafety-related that affect operational performance of the unit.
- Category 4: AOVs in Maintenance Rule systems that do not meet the requirements of Categories 1, 2, or 3. Valves in this group are passive, safety-related with Low Safety Significance.

A system level design basis review (DBR), used to verify and document the adequacy of AOV sizing and setpoints, is required for Category 1 valves. The system level DBR consists of both a system level review and a component level review. The system level review identifies the worst case operating conditions under which an AOV must operate and maintain position within the licensing basis of the plant. System conditions identified / documented in the system level review include the following:

- Upstream and downstream line pressures
- Maximum differential pressure
- Fluid flow rate
- Fluid temperature

The results of the DBR calculations are used as inputs to the component level calculations, which establish AOV required actuator output capability, available actuator capability margin, and applicable setpoints.

2.2.4.2.2 Description of Analyses and Evaluations

Impact of the SPU on the following topics related to safety-related valves and pumps is evaluated:

3. Maximum allowable valve stroke times
4. Valve performance
5. Accident mitigation flow rates for check valves
6. Pump performance
7. Generic Letter 89-10
8. Generic Letter 96-05
9. Generic Letter 95-07

10. AOV Program

11. Lessons Learned

Since the description and results of the analyses and evaluations are interrelated, these elements of the Technical Evaluation are addressed in Section 2.2.4.2.3, Results.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above in Section 2.2.4.1, the Millstone Station “Closed-Cycle Cooling Water Systems” Program is addressed in License Renewal SER Section 3.0.3.2.4, and is described in a DNC Technical Report. As part of this program, surveillance testing of the reactor plant component cooling water pumps, control building chilled water pumps, charging pump seal cooling pumps, and the safety injection pump cooling pumps is performed per the IST Program to monitor component performance. The SPU does not affect the requirement to perform surveillance testing of these pumps per the IST Program in support of the “Closed-Cycle Cooling Water Systems” Program.

Aging effects of safety-related valves are primarily managed by the Chemistry Control for Primary Systems Program, Chemistry Control for Secondary Systems Program and Work Control Program. Because no new materials are being added within existing evaluation boundaries and because component internal and external environments (e.g., pressures, temperatures, chemical environment) remain within parameters previously evaluated or analysis demonstrates that equipment qualification is maintained at SPU conditions, implementation of the SPU does not diminish the ability of these program to provide reasonable assurance that the aging effects of safety-related valves will be effectively managed and that their functional performance will be maintained through the period of extended operation.

2.2.4.2.3 Results

1. **Maximum Allowable Valve Stroke Times**

MPS3 calculation, “MP3 – Active Response Times,” defines the maximum allowable stroke times for active valves within the scope of the IST Program, except for active valves which are check valves, relief valves, or non-powered manually operated valves. This calculation serves as backup for the ASME XI IWV test program, portions of the Technical Specifications, and the closure times for Containment isolation valves documented in FSAR Table 6.2-65, “Containment Penetration.”

Evaluation shows that the SPU does not affect the maximum allowable stroke times of power-operated active valves in the following systems:

- Auxiliary steam
- Steam generator blowdown
- Reactor plant component cooling
- Chilled water

- Containment Atmosphere Monitoring
- Containment Vacuum
- Reactor Plant Aerated Drains
- Reactor Plant Gaseous Drains
- Auxiliary feedwater
- Fire Protection, Water
- Turbine Plant Misc. Drains
- Feedwater (feedwater isolation trip valves, feedwater flow control valve, feedwater flow control valve bypass valves)
- Nitrogen System
- Hot Water Heating
- ESF building ventilation
- Instrument air
- Main steam (main steam isolation trip valves, main steam isolation trip valve bypass valves, turbine-driven auxiliary feedwater pump steam supply valves, turbine-driven auxiliary feedwater pump silencer drain valve)
- Primary Grade Water
- Quench spray
- Chemical Feed – Steam Generator
- Service water
- Reactor Plant Gaseous Vents
- Chemical Feed Chlorination

For power-operated active valves in the following systems, there are no changes in the maximum allowable stroke times due to the SPU:

- Charging pump cooling
- Chemical & volume control
- Control building air conditioning & ventilation
- Containment structure ventilation
- Reactor coolant
- Residual heat removal
- Containment recirculation
- High pressure safety injection

- Low pressure safety injection

2. **Valve Performance**

NSSS Scope Systems

Review of the following systems concludes that the existing maximum operating conditions (e.g., flowrates, pressures, and temperatures) remain valid for the SPU: reactor coolant system, chemical & volume control system, residual heat removal system, and safety injection system (post-LOCA injection phase). The safety injection pump head performance is not affected by the SPU, and therefore, safety injection system existing maximum operating conditions during the post-LOCA recirculation phase remain valid for the SPU. Accordingly, the SPU does not affect the performance characteristics/IST Program requirements of safety-related valves, including solenoid-operated valves, in these systems; maximum allowable valve open/close stroke times will continue to be met at SPU conditions (i.e., the valves will continue to stroke within the maximum allowable valve stroke times under SPU conditions).

Main Steam System

As addressed in Section 2.5.5.1, the SPU does not affect the existing set pressures of the main steam safety valves, and evaluations demonstrate that the capacity of the valves satisfy the original sizing criterion and overpressure protection requirements for the range of SPU NSSS design parameters. Accordingly, performance characteristics/IST Program requirements for these valves are not affected by the SPU.

As addressed in Section 2.5.5.1, the SPU does not affect the existing set pressure of the main steam pressure relieving air-operated valves, and evaluation of the total installed capacity of these valves indicates that the original design bases in terms of plant cooldown capability can be achieved for the range of NSSS design parameters approved for the SPU. Accordingly, performance characteristics/IST Program requirements for these valves are not affected by the SPU.

As addressed in Section 2.5.5.1, evaluations demonstrate existing main steam pressure relieving bypass valve flow capability is adequate to satisfy the design basis functional requirements inherent in the FSAR Chapter 15 safety analyses, the safety grade cold shutdown analysis, and the fire shutdown cooldown analysis at SPU conditions. Accordingly, performance characteristics of these valves are not affected by the SPU.

As addressed in Section 2.5.5.1, the impact of the higher main steam flow rates through the main steam isolation trip valves during SPU operation was evaluated; it was confirmed that these valves are not adversely affected in the open position during normal full power SPU operation and that the closure time of these valves is not affected by the SPU. Accordingly, the SPU does not affect the performance characteristics/IST Program requirements of these valves, and the maximum allowable close stroke time for these valves will continue to be met at SPU conditions.

As addressed in Section 2.5.5.1, the time to close for the main steam isolation trip valve bypass valves is not affected by the increased flow at SPU conditions. The maximum allowable close stroke time for these valves will continue to be met at SPU conditions.

As addressed in Section 2.5.5.1, the maximum allowable open stroke time for the auxiliary feedwater pump turbine steam supply air operated valves and the maximum allowable close stroke time for the auxiliary feedwater pump turbine exhaust pipe drain valve will continue to be met at SPU conditions.

Feedwater System

As addressed in Section 2.5.5.4, the feedwater flow control valves will provide the required flow at the required pressure drop at SPU conditions. Therefore, the performance characteristics of these valves are not affected by the SPU. As also addressed in Section 2.5.5.4, the feedwater flow control valves, along with their associated bypass valves, and the feedwater isolation trip valves have been evaluated for the increased flow rates, differential pressures, and temperatures at SPU conditions. The maximum allowable close stroke time for these valves will continue to be met at SPU conditions.

Auxiliary Feedwater System

Evaluation shows that the SPU does not affect the maximum operating conditions (e.g., flow rates, pressures, and temperatures) in the auxiliary feedwater system. Therefore, the SPU does not affect the performance characteristics/IST Program requirements of safety-related valves, including solenoid-operated valves, in this system, and maximum allowable valve open stroke times will continue to be met at SPU conditions.

Reactor Plant Component Cooling Water System

Evaluation shows that the RPCCW system conditions are affected by the SPU, as follows: increases in operating flow rates are less than five percent, increases in pressures are less than 1 percent, and the maximum temperature is 145°F.

As addressed below in Item 6, Impact of the SPU on MOV System Parameters, for MOVs in balance of plant scope systems, which includes the RPCCW system, the results of the evaluations show the following:

- The SPU does not affect the maximum differential pressures/line pressures determined in the system and functional design basis review calculations.
- The MOV flow rates documented in the system and functional design basis review calculations for MOVs in the above-listed BOP scope systems at current conditions are not affected by the SPU or bound the flow rates at SPU conditions (for RPCCW MOVs, the current flow rates bound the SPU flow rates).
- The fluid temperatures documented in the system and functional design basis review calculations at current conditions are not affected by the SPU or the maximum temperatures at current conditions bound the temperatures at SPU conditions (for RPCCW MOVs, the maximum temperatures documented in the calculations at current conditions bound the temperatures at SPU conditions).

Therefore, the SPU does not affect the performance characteristics of safety-related MOVs in this system, and maximum allowable valve close stroke times will continue to be met at SPU conditions.

Evaluation shows that the slight increases in RPCCW System flow rates and pressures will not have a significant affect on the performance of safety-related AOVs in this system. Based on evaluation of the increase in temperature on safety-related AOVs in this system, there were no requirements that would be adversely affected by the fluid temperature increase (e.g., valve structural limitations, evaluations of thrust/torque capability), and therefore the temperature increase will not affect the performance of the safety-related AOVs in this system. Analysis shows that the temperature control valves in the discharge line and bypass line of the RPCCW heat exchangers will continue to maintain the required RPCCW supply temperatures at SPU conditions. Accordingly, there is no significant affect on the performance characteristics of safety-related AOVs in this system due to the SPU, and maximum allowable valve close stroke times will continue to be met at SPU conditions

Steam Generator Blowdown System

As addressed in Section 2.1.10, the predicted SPU operating temperatures and pressures in the steam generators, steam generator blowdown tank and interconnecting piping and valves decrease slightly relative to current conditions. Since the steam generator blowdown system pressure at SPU conditions is bounded by the pressure at current conditions, and since the blowdown flow rate for each steam generator when blowing down all four steam generators at SPU conditions is bounded by the design flow rate for the steam generator blowdown air-operated Containment isolation valves, these valves will continue to meet the maximum allowable close stroke times at SPU conditions.

Service Water System

As addressed in Section 2.5.4.2, the SPU does not affect the flow rates and operating pressures in the service water system; however, the higher heat loads for the reactor plant component cooling water heat exchanger and the turbine plant component cooling water heat exchanger result in higher service water outlet temperatures.

As addressed below in Item 6, Impact of the SPU on MOV System Parameters, system parameters for MOVs in balance of plant scope systems, which includes the service water system, the results of the evaluations show that the fluid temperatures documented in the system and functional design basis review calculations at current conditions are not affected by the SPU or the maximum temperatures at current conditions bound the temperatures at SPU conditions (for service water MOVs, the temperatures documented in the calculations at current conditions are not affected by the SPU).

The impact of the increase in service water temperature on safety-related AOVs in this system has been evaluated. It was determined that there were no requirements that would be adversely affected by the fluid temperature increase (e.g., valve structural limitations, evaluations of thrust/torque capability), and therefore, the higher service water outlet temperatures at SPU conditions will not affect the performance of the safety-related AOVs in this system.

Based on the above, the SPU does not affect the performance characteristics/IST Program requirements of safety-related valves in this system, and maximum allowable valve open/close stroke times will continue to be met at SPU conditions.

Ventilation Systems

As addressed in Section 2.7.3, 2.7.6, and 2.7.7, the SPU does not affect the Control Building ventilation system, ESF Building ventilation system, or the Containment ventilation system. Accordingly, the maximum allowable open/close stroke times for valves in these systems will continue to be met at SPU conditions.

Other Systems

For the following systems, evaluations show that the existing maximum operating conditions (e.g., flowrates, pressures, temperatures) are not affected by the SPU, and therefore the SPU does not affect the performance characteristics/IST Program requirements of safety-related valves in these systems, and valve maximum allowable open/close stroke times will continue to be met at SPU conditions.

- Containment recirculation system (lines outside of Containment, which contain safety-related MOVs)
- Quench spray system
- Auxiliary steam system
- Chilled water system
- Instrument air system

3. **Accident Mitigation Flow Rates for Check Valves**

MPS3 calculation, “Flow Rates for Check Valves in the ASME Section XI In-Service Test Program,” documents the minimum required accident mitigation flow rates for that accident scenario requiring the largest flow rate, for check valves included in the scope of the IST Program. The SPU does not affect the minimum required accident mitigation flow rates for check valves in the following systems:

- Emergency diesel fuel
- Emergency diesel intercooler water
- Control building chilled water
- Main steam
- Quench spray
- Containment recirculation
- Fuel pool cooling and purification
- Service water

For check valves in the following systems, impact of the SPU on the minimum required accident mitigation flow rates will be revised as required as part of the SPU implementation phase:

- Charging pump cooling

- Safety injection pump cooling
- Chemical & volume control
- Reactor coolant
- Residual heat removal
- High pressure safety injection
- Low pressure safety injection
- Auxiliary feedwater
- Reactor plant component cooling water

4. **Pump Performance**

Pumps tested in the IST Program include the following:

- Reactor plant component cooling water pumps
- Boric acid transfer pumps
- Chemical & volume control charging pumps
- Charging pump cooling pumps
- Emergency generator fuel oil transfer pumps
- Motor driven steam generator auxiliary feed pumps
- Turbine driven auxiliary feedwater pump
- Control building chilled water pumps
- Quench spray pumps
- Residual heat removal pumps
- Containment recirculating pumps
- Fuel pool cooling pumps
- Safety injection pumps
- Safety injection pump cooling pumps
- Service water pumps
- Control Building air conditioning booster pumps
- MCC and Rod Control Area air conditioning booster pumps

There is no change in the pump head performance of the above-listed pumps at SPU conditions, and therefore, the IST Program requirements for these pumps are not affected by the SPU.

5. **Generic Letter 89-10**

Impact of the SPU on MOV System Parameters

The system and functional design basis review calculations for the GL 89-10 MOVs in the following balance-of-plant (BOP) scope systems were reviewed.

- Reactor plant component cooling water system
- Service water system
- Main steam system
- Auxiliary feedwater system
- Quench spray system
- Containment recirculation system
- Instrument air system

As an example of the review process used, Table 2.2.4-1 shows the evaluations of several valves in these BOP scope systems. The results of the evaluations show that the SPU does not affect the maximum differential pressures/line pressures determined in the system and functional design basis review calculations for the GL 89-10 MOVs in the BOP scope systems, and therefore, these parameters do not affect the calculations which determine MOV thrust and torque values for these MOVs.

The results of the evaluations show that the MOV flow rates documented in the system and functional design basis review calculations for MOVs in the above-listed BOP scope systems at current conditions are not affected by the SPU or bound the flow rates at SPU conditions.

The results of the evaluations show that the fluid temperatures documented in the system and functional design basis review calculations for MOVs in the above-listed BOP scope systems at current conditions are not affected by the SPU or the maximum temperatures at current conditions bound the temperatures at SPU conditions.

The system and functional design basis review calculations for the GL 89-10 MOVs in the following nuclear steam supply system (NSSS) scope systems were reviewed.

- Reactor coolant system
- Residual heat removal system
- Low pressure safety injection system
- High pressure safety injection system
- Chemical & volume control system

As an example of the review process used, Table 2.2.4-2 shows the evaluations of several valves in these NSSS scope systems. The results of the evaluations show that the SPU does not affect the maximum differential pressures/line pressures determined in the system and functional design basis review calculations for the GL 89-10 MOVs in the NSSS scope systems, and therefore, these parameters do not affect the calculations which determine MOV thrust and torque values for these MOVs.

The results of the evaluations show that the MOV flow rates documented in the system and functional design basis review calculations for the above-listed NSSS scope systems are not affected by the SPU.

The results of the evaluations show that the fluid temperatures documented in the system and functional design basis review calculations for the above-listed NSSS scope systems are not affected by the SPU or the maximum temperatures at current conditions bound the temperatures at SPU conditions.

Impact of the SPU on MOV Motor Capability Torque Values

As discussed above in Section 2.2.4.2.1, the MOV motor capability torque under elevated ambient temperature and degraded voltage conditions is a function of (1) derated motor torque at elevated ambient temperature, and (2) degraded voltage conditions (i.e., minimum voltage factors).

The impact of the SPU on accident/normal environment temperatures in plant areas is addressed in Section 2.3.1. With the exception of the accident environment temperature in the MSVB, the accident/normal environment temperatures in plant areas are not affected by the SPU. A main steam line break (MSLB) in the MSVB at SPU conditions results in a higher ambient temperature than the temperature resulting from a MSLB at current conditions. However, a thermal lag analysis is performed to show that the maximum temperature to be used for qualification of equipment in the MSVB at SPU conditions does not exceed the maximum temperature used for equipment qualification at current conditions. Therefore, the SPU does not affect the maximum ambient temperatures used in the determination of MOV motor capability torque values at current conditions.

With the exception of the GL 89-10 MOVs in the MSVB, the SPU does not affect the MOV available motor terminal voltage values/minimum voltage factors based on the following: As indicated in Section 2.3.3, there are no changes to the available voltage at the 480V motor control center (MCC) buses under the worst case accident scenario at SPU conditions. With the exception of cables in the MSVB, the cables routed from the MCC buses to the MOVs are not affected, since, as discussed above, with the exception of the MSVB accident temperature, the normal and accident temperature data for plant structures are not affected by the SPU.

An evaluation of the impact of the SPU on the existing MOV motor terminal voltage values/ minimum voltage factors for the GL 89-10 MOVs located in the MSVB was performed. The Main Steam Pressure Relieving Bypass Valves are not required to operate during a main steam line break (MSLB) in the MSVB, and therefore the minimum voltage factors for these MOVs are not affected by the SPU. The Steam Generator Pressure Relief Isolation Valves are required to be qualified to operate following a Turbine Plant Miscellaneous Drains (DTM) system line break in the MSVB. Using an accident temperature of 500°F due to the DTM line break at SPU conditions, the evaluation shows that the effect of increased temperature due to the SPU on the existing minimum voltage factors for the Steam Generator Pressure Relief Isolation Valves is not significant, i.e., less than 1.2 percent change.

Impact of the SPU on MOV Valve Factors/Required Thrusts

Most required thrusts to operate gate and globe valves are determined using EPRI MOV PPM (Performance Prediction Methodology) and a small amount through dynamic testing. EPRI MOV PPM derived thrusts for gate valves are dependent on guide or seat to wedge friction, which changes according to the fluid temperature. As discussed above, the fluid temperatures documented in the system and functional design basis review calculations for MOVs in BOP and NSSS scope systems at current conditions are not affected by the SPU or the maximum temperatures at current conditions bound the temperatures at SPU conditions. Gate valves with measured valve factors will not be affected, as the temperature is not a part of the tested valve factor determination.

Thus, the SPU has no impact on MOV valve factors/required thrusts.

6. **Generic Letter 96-05**

No MOVs are required to be added to the MOV Program as a result of the SPU.

As discussed above, the SPU does not affect the differential pressures determined in the system and functional design basis review calculations.

The results of the Probabilistic Risk Assessment (PRA) are used in the determination of the risk category of MOVs in the program. As addressed in Section 2.13, the PRA model has been updated for the SPU. The risk categories of the MOVs in the GL 96-05 program will be updated as required based on the results of the updated PRA model. Any changes in the periodic verification requirements as a result of changes in risk category due to the SPU will be addressed in accordance with MPS3 GL 96-05 program requirements.

7. **Generic Letter 95-07**

Twenty-four motor-operated gate valves were previously modified to eliminate the potential for pressure locking during a safety-related open stroke. The modifications (e.g., hole drilled in disc, bypass line from bonnet to body) relieve pressure in the bonnet area of the valves, thus eliminating the potential for pressure locking of the valve disc. Other motor-operated gate valves either are not susceptible to pressure locking due to the valve design (i.e., valve is a solid disc gate valve) or the valve does not have a safety-related opening stroke.

MPS3 pressure locking/thermal binding calculation (identified in Section 2.2.4.2.1) identifies the motor-operated gate valves that are not susceptible to thermal binding due to the valve design (i.e., valve is a parallel disc gate valve), and also those that do not have a safety-related opening stroke. For the remaining valves, the calculation includes evaluations that demonstrate that the valves are not susceptible to thermal binding. These evaluations were reviewed for impact of the SPU, and it was determined that the SPU does not affect the evaluation results. As an example of the review process used, Table 2.2.4-3 shows the evaluations performed for several valves.

The SPU does not affect motor-operated valve design/modifications, and does not affect the functional designation of a valve’s strokes as safety-related or non-safety-related. The SPU does not affect the evaluations that show that affected valves are not susceptible to thermal binding.

The SPU does not create any new conditions which would affect the susceptibility of motor-operated gate valves to pressure locking or thermal binding.'

8. **AOV Program**

The system level design basis review calculations for the Category 1 AOVs in the following systems were reviewed:

- Main steam system (main steam pressure relieving valves, turbine-driven auxiliary feedwater pump steam supply valves)
- Service water system (service water diesel generator heat exchanger outlet valves)
- Chemical and volume control system (reactor coolant letdown inside/outside Containment isolation valves)

The results of the evaluations show that the SPU does not affect the maximum differential pressures/line pressures, flow rates, or fluid temperatures documented in the system level design basis review calculations for the Category 1 AOVs in these systems. Therefore, the SPU does not affect the AOV setup values determined in the component level calculations for these AOVs.

Category 2 AOVs include the feedwater flow control valves and associated bypass valves and the steam generator blowdown Containment isolation valves. These are addressed above in Section , Item 2.

9. **Lessons Learned**

Millstone MOV Program Instruction PI-19 provides guidance for receiving, evaluating, and incorporating industry experience pertaining to MOVs into the MOV Program. Millstone maintains the “OE One Stop Shop” website to provide quick access to sources of both in-house and industry operating experience. The INPO Newsgroup OE Forum is monitored daily via automatic e-mail notification based on the key word “MOV.” During review of operating experience, if an adverse condition is identified which affects MPS3, a Condition Report is generated in accordance with station requirements. All applicable issues are placed in the Corrective Action Program via Condition Reports.

Data on AOV performance collected through industry-wide cooperation is utilized to enhance the AOV Program. Personnel responsible for AOV Program implementation participate and interact with industry groups dedicated to the enhancement of AOV performance, including EPRI, the AOV User’s Group, the Westinghouse Owner’s Group, and the Institute for Nuclear Power Operations.

2.2.4.3 Conclusion

DNC has reviewed the assessments related to the functional performance of safety-related valves and pumps and concludes that the effects of the proposed SPU on safety-related pumps and valves have been adequately addressed. DNC further concludes that the effects of the proposed SPU on motor-operated valve programs related to GL 89-10, GL 96-05, and GL 95-07 have been adequately evaluated, and that the lessons learned from those programs to other safety-related power-operated valves has been addressed. Based on this, DNC concludes that it has been demonstrated that safety-related valves and pumps will continue to meet the MPS3 licensing basis with respect to the requirements of GDC-1, GDC-37, GDC-40, GDC-43, GDC-46, GDC-54, and 10 CFR 50.55a)(f) following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to safety-related valves and pumps.

Table 2.2.4-1 Impact of SPU on System Parameters for GL 89-10 MOVs in BOP Systems

MOV(s)	Valve Name / Function	MOV System Parameters at Current Plant Conditions	Impact of SPU on MOV System Parameters at Current Plant Conditions
		<u>Notes</u>: 1. In this table: • Valve stroke in the open direction is identified by “(O)” and stroke in the closed direction is identified by “(C).” • Direction of flow is identified by “(F)” for forward flow and “(R)” for reverse flow. 2. In the MOV System Design Basis Review analyses evaluated in this table, certain calculations for maximum pump head utilize a diesel generator frequency change of 0.8 Hz based on Technical Specification 4.8.1.1.2. This parameter is not affected by the SPU.	

Table 2.2.4-1 Impact of SPU on System Parameters for GL 89-10 MOVs in BOP Systems

MOV(s)	Valve Name / Function	MOV System Parameters at Current Plant Conditions	Impact of SPU on MOV System Parameters at Current Plant Conditions
3SWP*MOV 24A/B/C/D	Service Water Pump Discharge Strainer Backwash MOV	Safety-Related (O) Stroke:	
		Max. upstream line pressure (O): 101 psig, based on SWP pump shutoff head and elevation static head	SWP pump head performance not affected by the SPU. Design flood level of the bay not affected by the SPU. Elevation of MOVs not affected by the SPU.
		Min. downstream line pressure (O): 0 psig, based on downstream line discharging to the bay	Not affected by the SPU
		Max. differential pressure (O): 101 psid	Not affected by the SPU
		Flow rate (F): 1000 gpm	SWP system flow rates not affected by the SPU.
		Fluid temperature (°F): 33–75	Not affected by the SPU
3FWA*MOV 35A/B/C/D	Auxiliary Feedwater Isolation MOV	Safety-Related (C) Stroke / Forward Flow:	
		Upstream line pressure (C): 1570 psig, based on motor-driven FWA pump shutoff head and elevation static head	Motor-driven FWA pump head performance not affected by the SPU. Elevation of DWST overflow line and elevation of MOVs not affected by the SPU.
		Downstream line pressure (C): (-) 5 psig, based on minimum Containment pressure per Technical Specification 3.6.1.4	Minimum Containment pressure per Technical Specification 3.6.1.4 not affected by the SPU.
		Max. differential pressure (C): 1575 psid	Not affected by the SPU.
		Flow rate (F) (C): 650 gpm, based on motor-driven FWA pump curve	Motor-driven FWA pump curve not affected by the SPU.
		Fluid temperature (°F) (C): 40–100	Not affected by the SPU

Table 2.2.4-2 Impact of SPU on System Parameters for GL 89-10 MOVs in NSSS Systems

MOV(s)	Valve Name / Function	MOV System Parameters at Current Plant Conditions	Impact of SPU on MOV System Parameters at Current Plant Conditions
		<u>Notes</u>: 1. In this table: • Valve stroke in the open direction is identified by "(O)" and stroke in the closed direction is identified by "(C)." • Direction of flow is identified by "(F)" for forward flow and "(R)" for reverse flow. 2. In the MOV System Design Basis Review analyses evaluated in this table, certain calculations for maximum pump head utilize a diesel generator frequency change of 0.8 Hz based on Technical Specification 4.8.1.1.2. This parameter is not affected by the SPU.	

Table 2.2.4-2 Impact of SPU on System Parameters for GL 89-10 MOVs in NSSS Systems

MOV(s)	Valve Name / Function	MOV System Parameters at Current Plant Conditions	Impact of SPU on MOV System Parameters at Current Plant Conditions
3SIH*MV 8801A/B	Charging Pump to RCS Cold Leg Injection Isolation MOV	<u>Safety-Related (C) Stroke / Forward Flow</u>:	
		Upstream line pressure (C): 2745 psig, based on the highest shutoff head of the 3 CHS pumps, and elevation static head using elevation of the RWST overflow line	CHS pump head performance not affected by the SPU. Elevation of RWST overflow line and elevation of MOVs not affected by the SPU
		Downstream line pressure (C): 0 psig, based on an assumed post accident passive failure downstream of the MOV	Not affected by the SPU
		Max. differential pressure (C): 2745 psid	Not affected by the SPU.
		Flow rate (F): 560 gpm, based on a single CHS pump running, as given in Tech. Spec. 4.5.2.	Max. flow rate of 560 gpm given in Tech. Spec. 4.5.2 not affected by the SPU
		Fluid temperature (°F): 150, max. Containment temperature 24 hours following a DBA	Not affected by the SPU
3CHS*MV 8104	Emergency Boration MOV	<u>Safety-Related (O) Stroke / Forward Flow</u>:	
		Upstream line pressure (O): 137 psig, based on boric acid transfer pump shutoff head, and elevation static head using boric acid tank overflow level	Boric acid transfer pump head performance not affected by the SPU. Elevation of boric acid tank overflow nozzle not affected by the SPU. Elevation of MOV not affected by the SPU.
		Downstream line pressure (O): 2 psig, based on elevation static head using elevation of RWST suction level	Elevation of RWST suction nozzle and elevation of MOV not affected by the SPU.
		Max. differential pressure (O): 135 psid	Not affected by the SPU.
		Flow rate (F): 75 gpm, boric acid transfer pump flow rate	Boric acid transfer pump flow rate not affected by the SPU.
		Fluid temperature (°F): Ambient	Not affected by the SPU

Table 2.2.4-3 Impact of the SPU on Evaluations of Susceptibility of MOVs to Thermal Binding (TB)

MOV(s)	Valve Name / Function	Summary of Current Evaluation Showing MOV Is Not Susceptible to TB	Impact of SPU on Current Evaluation
3RHS*MV 8701A, 8701C 3RHS*MV 8702B, 8702C	RHS Pump P1A Suction from RCS Hotleg 1 Isolation MOV RHS Pump P1B Suction from RCS Hotleg 4 Isolation MOV	Valves are located in the Containment. The valves are stroked closed during plant heatup prior to the reactor coolant system (RCS) reaching 200°F. They are stroked open to support plant cooldown using the residual heat removal system (RHS) when the RCS temperature is less than 350°F. However, since the valves are located in a dead leg of piping the opening stroke could occur at the minimum normal ambient temperature in the Containment of 70°F. The resulting differential temperature is 130°F or less. Per MOV Program Instruction PI-20, the differential temperature below which thermal binding will not occur in a flexible wedge gate valve, based on design considerations, is 150°F. Therefore, the valves are not susceptible to thermal binding.	The SPU does not affect the operational action of closing these valves during plant heatup prior to the RCS reaching 200°F. The SPU does not affect the minimum normal ambient temperature in the Containment.
3RSS*MV 8837A/B	Containment Recirculation System Cross-Connect MOV	Valves are located in the ESF Building. They are normally closed and are opened during alignment of the RSS and RHS systems for post-accident cold leg recirculation. Assuming the valves are closed at the maximum normal ambient temperature of 120°F and are opened at the minimum normal ambient temperature of 50°F, the maximum differential temperature is 70°F. Per MOV Program Instruction PI-20, the differential temperature below which thermal binding will not occur in a flexible wedge gate valve, based on design considerations, is 150°F. Therefore, the valves are not susceptible to thermal binding.	The SPU does not affect the normal ambient temperature range in the ESF Building.

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

2.2.5.1 Regulatory Evaluation

Mechanical and electrical equipment covered by this section includes equipment associated with systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal. Equipment associated with systems essential to preventing significant release of radioactive materials to the environment are also covered by this section. The DNC review focused on the effects of the proposed SPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated with pipe whip and jet impingement forces. The primary input motions due to the SSE are not affected by an SPU.

The acceptance criteria for this review are

- GDC-1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.
- GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions.
- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.
- GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture.
- GDC-30, insofar as it requires that components that are part of the RCPB be designed, fabricated, erected, and tested to the highest quality standards practical.
- 10 CFR 100, Appendix A, which sets forth the principal seismic and geological considerations of the seismic and geologic characteristics of the plant site.
- 10 CFR 50, Appendix B, which sets forth quality assurance requirements for safety-related equipment.

Specific review criteria are contained in SRP Section 3.10, and are also identified in Matrix 2 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, SRP Section 3.10, Rev. 2, July 1981.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 design relative to conformance to

- GDC-1 is described in FSAR Section 3.1.2.1, Quality Standards and Records (Criterion 1), as follows:

  Structures, systems, and components important to safety are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

  Quality standards applicable to safety-related structures, systems, and components are generally contained in codes such as the ASME Boiler and Pressure Vessel Code. The applicability of these codes is specifically identified throughout this report and is summarized in FSAR Section 3.2.5. Chapter 17 provides direct reference to the Quality Assurance Program established to provide assurance that safety related structures, systems, and components satisfactorily perform their intended safety functions. The reference documents contain the procedures for generating and maintaining appropriate design, fabrication, erection, and testing records.

- GDC-2 is described in FSAR Section 3.1.2.2, Design Bases for Protection Against Natural Phenomena (Criterion 2).

  Those features of plant facilities that are essential to the prevention of accidents that could affect the public health and safety or to the mitigation of accident consequences are designed to:

  1. Quality standards that reflect the importance of the function to be performed. Approved design codes are used when appropriate to the nuclear application.

  2. Performance standards that enable the facility to withstand, without loss of the capability to protect the public, the additional forces imposed by the most severe earthquake, flooding condition, wind, ice, or other natural phenomena for the site, and credible combinations of the effects of normal and accident conditions with the effects of the natural phenomena.

  Features of the facility essential to accident prevention and mitigation of accident consequences, which are designed to withstand the effects of natural phenomena, are

  1. The reactor coolant pressure boundary and containment barriers.

  2. The controls and emergency cooling systems whose functions are to maintain the integrity of these barriers.

  3. Systems which depressurize the containment following a loss of coolant accident (LOCA).

  4. Power supply and essential services.

  5. Reactivity systems, monitoring systems, and fuel systems.

  6. The components used to store and cool spent reactor fuel.

All piping, components, and supporting structures of the reactor and safety-related systems are designed to withstand a specified seismic disturbance and credible combinations of effects of normal and accident conditions coincident with the effects of natural phenomena. Plant design criteria specify that there is to be no loss of function of such equipment in the event of the SSE ground acceleration acting in the horizontal and vertical directions simultaneously. The dynamic response of Seismic Category I structures to ground acceleration, based on an envelope of characteristics of the site foundation soils and on the critical damping of the foundation and structures, is included in the design analysis.

Design of structures for protection against natural phenomena is described in FSAR Section 3.8. Safety-related structures have sufficient capacity to accept a combination of normal operating loads, functional loads due to the design basis accident (DBA), and the loadings imposed by the maximum wind velocity, or those due to the SSE, whichever is the larger.

The emergency onsite power sources are not subject to interruption due to earthquake, windstorm, floods, or to disturbances on the external power transmission system.

Power cabling, motors, and other equipment required for operation of the engineered safety features are suitably protected against the effects of the design basis accident (DBA) and from severe external weather conditions, as applicable.

Unit design criteria which ensure protection against natural phenomena are described in FSAR Section 3.2,Classification of Structures, Systems, and Components; FSAR Section 3.3, Wind and Tornado Loadings; Section 3.4, Water Level Design; and Section 3.7, Seismic Design.

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4), as follows:

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

  In a letter from B. J. Youngblood (NRC) to J. F. Opeka (NNECO) dated June 5, 1985, MPS3 was granted an exemption for a period of two cycles of operation from those portions of General Design Criterion 4 which require protection of structures, systems, and components from the dynamic effects associated with postulated breaks in the reactor coolant system primary loop piping.

  In Federal Register, Volume 51, No. 70, dated April 11, 1986, the NRC published a final rule modifying General Design Criterion 4 to allow use of leak-before-break technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in pressurized water reactors. This rule obviates the need for the above exemption.

Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-14 is described in FSAR Section 3.1.2.14, Reactor Coolant Pressure Boundary (Criterion 14), as follows:

  The reactor coolant system boundary is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits (FSAR Section 3.9). Reactor coolant pressure boundary materials, selection, and fabrication techniques ensure a low probability of gross rupture or abnormal leakage.

  In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions, such as seismic and pipe rupture, as discussed in FSAR Sections 3.6 and 3.7. The system is protected from overpressure by means of pressure relieving devices as required by applicable codes (FSAR Section 5.2.2).

  The reactor coolant system boundary has provisions for inspection, testing, and surveillance of critical areas to assess the structural and leaktight integrity (FSAR Section 5.2). For the reactor vessel (FSAR Section 5.3), a material surveillance program conforming to applicable codes is provided.

- GDC-30 is described in FSAR Section 3.1.2.30, Quality of Reactor Coolant Pressure Boundary (Criterion 30), as follows:

  Reactor coolant pressure boundary components are designed, fabricated, inspected, and tested in conformance with ASME Nuclear Power Plant Components Code, Section III. All components are classified according to ANSI N18.2-73 and N18.2a-75 and are accorded the quality measures appropriate to the classification. The design bases and evaluations of reactor coolant pressure boundary components are discussed in FSAR Chapter 5.

  Leakage is detected by an increase in the amount of makeup water required to maintain a normal level in the pressurizer. The reactor vessel closure joint is provided with a temperature monitored leakoff between double gaskets. Leakage into the reactor containment is drained to the reactor building sump where it is monitored.

  Leakage is also detected by measuring the airborne and gaseous activity and activity of the condensate drained from the reactor building air recirculation units. Monitoring the inventory of reactor coolant in the system at the pressurizer, volume control tank, and coolant drain collection tanks make available an accurate indication of integrated leakage.

  FSAR Section 5.2.5 discusses the reactor coolant pressure boundary leakage detection system.

- 10 CFR 100, Appendix A, Seismic and Geologic Siting Criteria, is described in FSAR Section 2.5.2.7, Operating Basis Earthquake, as follows:

  In accordance with 10 CFR 100, Appendix A, the OBE is taken to be at least one half of the SSE, or 0.09 g.

- 10 CFR 50, Appendix B, Quality Assurance 18 Point Criteria, is described in FSAR Section 17.1, Quality Assurance Program Topical Report, as follows:

  A comprehensive Quality Assurance Program has been developed to assure conformance with established regulatory requirements, set forth by the Nuclear Regulatory Commission, and accepted industry standards. The participants in the QAP assure that the design, procurement, construction, testing, operation, maintenance, repair, and modification of nuclear power plants are performed in a safe and effective manner. The QAPD Topical Report complies with the requirements set forth in 10 CFR 50, Appendix B.

GL-87-02, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue, was addressed to all holders of operating licenses not reviewed to current licensing criteria on seismic qualification of equipment. Current licensing criteria, as applicable to this issue, were defined in NUREG-1211, Regulatory Analysis for Resolution of Unresolved Safety Issue A-46, Seismic Qualification of Equipment in Operating Plants, Section 1, Plants Affected, February 1987. This document identified the current requirements for qualification of equipment in licensing as being defined in RG 1.100, IEEE Standard 344-1975. The FSAR specifically states in Section 3.10B.1 that “The earthquake requirements and qualification methods conform to those outlined in IEEE Standard 344-1975, IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations, (Section 1.8, R.G. 1.100) and are in agreement with the recommendations of Branch Technical Position EICSB 10.” Therefore, USI A-46 does not apply to MPS3. This conclusion was documented in a letter from G. D. Hicks to NRC, dated July 21, 1997, and was accepted by a letter from P. F. McKee (NRC) to N. S. Carns (NNECO), dated September 4, 1997.

Seismic Category I equipment and components are documented for seismic adequacy. The basic source of seismic design data is the ground response spectra, the amplified response spectra, floor, or mat time history, derived through a dynamic analysis of the relevant structure. Refer to FSAR Section 3.7B for information pertaining to seismic design as well as seismic analysis performed for SSC within the scope of the BOP. Refer to FSAR Section 3.7N for information pertaining to the seismic analysis performed for subsystems within the NSSS scope of responsibility.

The methods and procedures used in the design and qualification of Seismic Category I mechanical equipment within the BOP scope are outlined in FSAR Sections 3.7B.3.1.1 and 3.9B.3. Refer to FSAR Section 3.9N for information on the design and qualification of mechanical systems comprising the NSSS scope of supply.

Safety-related instrumentation and electrical equipment within the BOP scope of supply is seismically qualified in accordance with general instructions for earthquake requirements as discussed in FSAR Section 3.10B. In order to prevent any threat of impacting damage to Class 1E equipment during seismic events, non-safety-related instrumentation and electrical equipment located adjacent to Class 1E equipment is also seismically qualified. The earthquake requirements and qualification methods conform to those outlined in IEEE Standard 344-1975, IEEE Recommended Practices for Seismic Qualifications of Class 1E Equipment for Nuclear Power Generating Stations (see FSAR Section 1.8, R.G. 1.100), and are in agreement with the recommendations of Branch Technical Position ICSB 10. Instrumentation and electrical equipment are tested as individual components, either as part of a simulated structural section or as part of a completely assembled module or unit. Refer to FSAR Section 3.10N for information pertaining to the seismic qualification of safety-related instrumentation and electrical equipment classified as Seismic Category I that are within the NSSS scope of supply.

The safety class definitions and classification lists are given in FSAR Section 3.2.

Concerning the qualification of Seismic Category I equipment to withstand dynamic effects associated with pipe whip and jet impingement forces, refer to FSAR Section 3.6 for descriptions of the design criteria and bases for protecting essential equipment from the effects of piping failures inside and outside of containment.

FSAR Table 1.9-1 summarizes the differences between the FSAR and the acceptance criteria given in SRP Section 3.10, Rev. 2, for equipment in BOP scope systems and NSSS scope systems. FSAR Table 1.9-2 provides justifications for these differences.

MPS3 systems and components were evaluated for continued acceptability for the purpose of plant license renewal. The results of that review are documented in NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, Rev. 18. These system/component evaluations are addressed in the respective system evaluations contained in the License Renewal SER.

2.2.5.2 Technical Evaluation

2.2.5.2.1 Introduction

This section addresses impact of the SPU on the qualification of equipment to withstand seismic events and the dynamic effects associated with pipe whip and jet impingement forces.

2.2.5.2.2 Description of Analyses and Evaluations

The impact of the SPU on seismic design, seismic inputs, and seismic loads was evaluated in order to determine the impact of the SPU on the seismic qualification of essential equipment and supports.

The impact of the SPU both on high-energy/moderate-energy line break locations and on the protection features currently in place for protection of essential equipment from the dynamic effects of pipe whip and jet impingement was addressed in order to determine the impact of the SPU on qualification of equipment to withstand the dynamic effects associated with pipe-whip and jet impingement.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed in Section 2.2.5.1, this review focused on the effects of the proposed SPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated with pipe whip and jet impingement forces. Changes due to the SPU that could affect seismic and dynamic qualification of equipment (e.g., addition of new materials) are reviewed as part of the license renewal effort on a system-by-system basis. These are addressed as required in respective LR sections.

2.2.5.2.3 Results

Seismic design is not impacted by the SPU since seismic requirements remain unchanged. There is no change to seismic inputs (amplified response spectra) or seismic loads resulting from the SPU. Therefore, the seismic qualification of essential equipment and supports remains unaffected by the SPU.

As addressed in Sections 2.2.1 and 2.5.1.3, the SPU does not result in any new or revised high-energy/moderate-energy line break locations and does not affect the protection features currently in place for protection of essential equipment from the dynamic effects of pipe whip and jet impingement (e.g. jet impingement shields). Therefore, the qualification of equipment to withstand the dynamic effects associated with pipe-whip and jet impingement forces is not affected by the SPU.

Since the SPU affects neither the seismic qualification of essential equipment and supports nor the qualification of equipment to withstand the dynamic effects associated with pipe-whip and jet impingement forces, conformance with the following continues to be met: GDCs -1, -2, -4, -14, and -30; conformance with 10 CFR 100, Appendix A; and conformance with 10 CFR 50, Appendix B. Also, the SPU does not affect the differences between the FSAR and the acceptance criteria given in SRP Section 3.10, Rev. 2, as documented in FSAR Tables 1.9-1 and 1.9-2.

Evaluations related to seismic and dynamic effects of the SPU are addressed in the following sections:

- Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects
- Section 2.2.2.1, NSSS Piping, Components and Supports
- Section 2.2.2.2, Balance of Plant Piping and Supports (Non-Class 1)
- Section 2.5.1.3, Pipe Failures

2.2.5.3 Conclusion

The DNC review of the effects of the proposed SPU on the qualification of mechanical and electrical equipment concludes that the review has (1) adequately addressed the effects of the proposed SPU on equipment and (2) demonstrated that the equipment will continue to meet the MPS3 current licensing basis with respect to the requirements of GDCs -1, -2, -4, -14, -30; 10 CFR 100, Appendix A; and 10 CFR 50, Appendix B. Therefore, the proposed SPU is acceptable with respect to the qualification of mechanical and electrical equipment.

2.2.6 NSSS Design Transients

2.2.6.1 Introduction

As discussed in FSAR Chapter 3, the reactor coolant system is designed to accommodate system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients (Reference 1). This evaluation compares the MPS3 design parameters developed for the proposed SPU to the design parameters used in the current design basis design transients. Where revisions were necessary, comparative analyses were performed and the transients revised, as needed, to reflect the operating conditions for the proposed SPU.

2.2.6.2 Regulatory Evaluation

NSSS design transients are developed for use in the analyses of the cyclic behavior of the NSSS SSCs. To provide the necessary high degree of integrity for them, the transient parameters selected for component fatigue analyses are based on conservative estimates of the magnitude and frequency of the transients resulting from various plant operating conditions. DNC review focused primarily on the effects of the proposed SPU on NSSS design parameters that are used in transient analyses and on how those differences in design parameters required revising the NSSS design transients. The acceptance criteria for this review are:

- GDC-1, insofar as it relates to safety-related components being designed, fabricated, erected, constructed, tested, and inspected in accordance with the requirements of applicable codes and standards commensurate with the importance of the safety-function to be performed.
- GDC-2, insofar as it relates to safety-related mechanical components of systems being designed to withstand seismic events without loss of capability to perform their safety function.
- GDC-14, insofar as it relates to the reactor coolant pressure boundary being designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.
- GDC-15, insofar as it relates to the mechanical components of the reactor coolant system being designed with sufficient margin to ensure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

Specific review criteria are contained in the SRP, Section 3.9.1, and other guidance provided in Matrix 2 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG 0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981. As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design basis transient analysis regarding conformance to

- GDC-1 is described in FSAR Section 3.1.2.1, General Design Criterion 1 - Quality Standards and Records.

  It is noted that all SSCs of the facility were classified according to their importance. The classification of structures and equipment is discussed in FSAR Section 3.2. SSCs were designed, fabricated, inspected, and erected, and the materials selected to the applicable provisions of the then recognized codes, good nuclear practice, and quality standards that reflected their importance. Discussions of applicable codes and standards, quality assurance programs, test provisions, etc., that were used are given both in FSAR Section 3.2 and in the ensuing sections in which the SSCs subject to the design transients are described. FSAR Section 17.1 describes a comprehensive QAP that has been developed to assure conformance with established NRC regulatory requirements and accepted industry standards. The participants in the QAP assure that the design, procurement, construction, testing, operation, maintenance, repair, and modification of nuclear power plants are performed in a safe and effective manner.

  The QAPD Topical Report complies with the requirements set forth in 10 CFR 50, Appendix B, and with applicable sections of the SAR for each license application. It is responsive to NUREG-0800, which describes the information presented in the quality assurance section of the SARs for nuclear power plants.

- GDC-2 is described in FSAR Section 3.1.2.2, General Design Criterion 2 - Design Bases for Protection Against Natural Phenomena.

  Specifically, GL 87-02, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue, was addressed to all holders of operating licenses not reviewed to current licensing criteria on seismic qualification of equipment. Current licensing criteria, as applicable to this issue, were defined in NUREG-1211, Regulatory Analysis for Resolution of Unresolved Safety Issue (USI) A-46, Seismic Qualification of Equipment in Operating Plants, February 1987, Section 1, Plants Affected. This document identified the current requirements for qualification of equipment in licensing as being defined in RG 1.100, Institute of IEEE Standard 344-1975. The FSAR specifically states in Section 3.10B.1. “The earthquake requirements and qualification methods conform to those outlined in IEEE Standard 344-1975, IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations, (Section 1.8, R.G 1.100) and are in agreement with the recommendations of Branch Technical Position EICSB 10.” Therefore, USI A-46 does not apply to MPS3. This conclusion was documented in a letter from G. D. Hicks to the NRC, dated July 21, 1997, and was accepted by a letter from P. F. McKee of the NRC to N. S. Carns of Northeast Utilities, dated September 4, 1997.

- GDC-14 is described in FSAR Section 3.1.2.14, General Design Criterion 14 - Reactor Coolant Pressure Boundary.

  The reactor coolant system boundary is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits as described in FSAR

Section 3.9. Reactor coolant pressure boundary materials, selection, and fabrication techniques ensure a low probability of gross rupture or abnormal leakage.

In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions, such as seismic and pipe rupture, as discussed in FSAR Sections 3.6 and 3.7. The system is protected from overpressure by means of pressure-relieving devices required by the applicable codes discussed in FSAR Section 5.2.2.

FSAR Section 5.2 discusses the reactor coolant system boundary and its provisions for inspection, testing, and surveillance of critical areas to assess the structural and leak-tight integrity. For the reactor vessel, FSAR Section 5.3 provides a material surveillance program conforming to applicable codes.

FSAR Section 5.3 notes that all piping components and supporting structures of the reactor coolant system are designed as Seismic Category I equipment, as defined in FSAR Section 3.7. All pressure-containing components of the reactor coolant system were designed, fabricated, inspected, and tested in conformance with the code requirements listed in Table 5.2-1 of FSAR. Therefore, the probability of abnormal leakage, of rapidly propagating failure, and of gross rupture is very low, and compliance with this criterion is assured.

- GDC-15 is described in FSAR Section 3.1.2.15, General Design Criterion 15 - Reactor Coolant System Design.

  The design pressure and temperature for each component in the reactor coolant and associated auxiliary control and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions. FSAR Sections 3.9 and 5.1 further discuss the NSSS design transients and the capability of the various components in the reactor coolant and connected auxiliary systems to withstand the effects of cyclic loads.

  Additionally, reactor coolant pressure boundary components achieve a large margin of safety by using proven ASME materials and design codes, proven fabrication techniques, nondestructive shop testing, and integrated hydrostatic testing of assembled components. FSAR Chapter 5 discusses the reactor coolant system design.

The MPS3 NSSS and associated auxiliary system components were evaluated for the continued acceptability and applicability of the design basis transients for the purpose of plant license renewal. The results of that review are found in NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005. The SER documents systems, structures, and components that are in scope for license renewal, as well as their associated materials of construction and environments, operating experience, and the programs credited for managing the potential aging effects. The NUREG 1838 SER Section 4 considers the frequency and severity of the operating transients assumed in the design of the SSCs of the MPS3 NSSS and associated auxiliary systems during the period of extended operation under the renewed operating license.

2.2.6.3 Technical Evaluation

2.2.6.3.1 Introduction

As part of the original design and analysis of NSSS components for MPS3, NSSS design transients (i.e., temperature and pressure transients) were specified 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 were 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 of possible significance to component cyclic behavior due to their severity or frequency that might occur during plant operations. 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 60-year operating license period of the plant.

As discussed in FSAR Chapter 3.9N, the systems, structures, and components important to safety in the reactor coolant system and its auxiliary systems are designed to withstand the effects of the cyclic loads from reactor coolant system temperature and pressure changes. Such cyclic loading is the result of normal unit load transients (i.e., design basis transients). The existing design basis transients were evaluated for the SPU. Comparative analyses were performed and the transients revised, as needed, to reflect the operating conditions for the proposed SPU.

2.2.6.3.2 Input Parameters, Assumptions, and Acceptance Criteria

NSSS design transients were based on the NSSS design parameters developed for the proposed SPU, presented herein in Section 1.1, Nuclear Steam Supply System Parameters, Reference 2. The design parameters on which the current applicable NSSS design transients are based were compared to the design parameters for the SPU and shown to be different for the values of NSSS power, reactor coolant system vessel T_{avg}, steam pressure, and feedwater temperature. Besides the NSSS power, the differences are due to RCS vessel T_{avg} and feedwater temperature windows. These differences were sufficient to require both a reassessment of the original NSSS design transients and the specification of revised NSSS design transients for the SPU.

2.2.6.3.3 Description of Analyses and Evaluations

The MPS3 design parameters for the proposed SPU were compared to the design parameters used in the current design transients. Where revisions were necessary due to sufficient differences between the two sets of operating conditions, evaluations and analyses of the existing applicable NSSS design transients were performed, and the transients were revised, as needed, to reflect the operating conditions for the SPU.

Impact On Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal Safety Evaluation Report (SER) for NSSS Design Transients. As stated in Section 2.2.6.2, the frequency and severity of operating transients were within the scope of License Renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal evaluation. Thus, SPU has no impact on the conclusions reached in the MPS3 license renewal SER regarding NSSS Design Transients.

2.2.6.3.4 Results

The NSSS design transients were used as input to the NSSS primary and secondary side component structural and fatigue analyses and evaluations. The acceptability of the design transients was determined by the results of the component stress and fatigue evaluations for each of the NSSS components discussed in this licensing report Section 2.2, Mechanical and Civil Engineering.

A list of the NSSS design transients applicable to the MPS3 SPU, with their associated design value frequencies of occurrence, are shown in Table 2.2.6-1. The transients listed and their associated frequencies of occurrence are unchanged from those in the current design basis list of transients. The design transients that were revised for the SPU are also noted in Table 2.2.6-1.

NSSS design transients are impacted by the SPU because of changes in plant operating conditions (i.e., design condition T_{hot}, T_{cold}, T_{avg}, RCS/pressurizer pressure, steam generator steam pressure, or feedwater temperature). The current applicable licensing basis transients were reviewed with respect to the SPU conditions, and changes to the transients were made for the SPU conditions, as applicable. The differences are due to RCS vessel T_{avg} and feedwater temperature windows for the SPU. In some cases, these differences were sufficient to require a reassessment of the original NSSS design transients.

Consistent with the current NSSS design transients, the revised NSSS design transients determined for the proposed SPU are conservative representations of transients that, when used as a basis for component remains appropriate for its application over the operating license period for MPS3.

2.2.6.4 Conclusion

Revised NSSS design transients were determined for the proposed SPU. These revised transients were used in the NSSS component structural and fatigue evaluations at SPU conditions. The results of structural and fatigue evaluations are provided in Section 2.2, Mechanical and Civil Engineering. The design life of the plant is 60 years.

DNC has reviewed the evaluation of the effects of the SPU on the NSSS design transients and concludes that the required design transient revisions have been adequately addressed. DNC further concludes that the revised NSSS design transients have been incorporated into the transient analysis of the safety-related NSSS systems and components and that MPS3 will continue to meet its current licensing basis requirements with respect to GDC-1, -2, -14, and -15. Therefore, DNC finds the SPU acceptable with respect to the NSSS design transients.

2.2.6.5 References

1. MPS3 Final Safety Analysis Report, Rev 18.6.

2. Westinghouse Performance Capability Working Group (PCWG), PCWG-06-9, PCWG Parameters for Millstone Unit 37 percent Stretch Power Uprate Program, April 25, 2006.

Table 2.2.6-1 List of Design Basis NSSS Design Transients

Transient Description	Number of Occurrences[a]	Revised for SPU
Normal Condition Transients		
1. Heatup and cooldown at 100°F/hr (pressurizer cooldown 200F/hr)	200	No
2. Unit loading and unloading at 5%/minute	13200	Yes
3. Step load increase and decrease of 10% of full power	2000	Yes
4. Large step load decrease with steam dump	200	Yes
5. Steady-state fluctuations a. Initial fluctuations b. Random fluctuations	 1.5×10^5 3.0×10^6	 Yes[b] Yes[b]
6. Feedwater cycling at hot shutdown	2000	No
7. Not used	-	-
8. Unit loading and unloading between 0% and 15% of full power	500	Yes
9. Boron concentration equalization	26400	No
10. Refueling	80	No
11. Reduced temperature return to power	2000	Yes
12. Reactor coolant pumps startup/shutdown	3800	No
13. Turbine roll test	20	No
14. Primary side leakage test	200	No
15. Secondary side leakage test	80	No
16. Tube leakage test	800	No
17. Heaters out of service		
a. One heater b. One bank of heaters	120 120	Yes Yes

Table 2.2.6-1 List of Design Basis NSSS Design Transients (Continued)

Transient Description	Number of Occurrences[a]	Revised for SPU
Upset Condition Transients		
1. Loss of load, without immediate reactor trip	80	Yes
2. Loss of power (blackout with natural circulation in the reactor coolant system RCS)	40	Yes
3. Partial loss of flow (loss of one pump)	80	Yes
4. Reactor trip from full power a. Without cooldown b. With cooldown, without safety injection c. With cooldown and safety injection	 230 160 10	 Yes Yes Yes
5. Inadvertent reactor coolant depressurization	20	Yes
6. Not Used	-	-
7. Control rod drop	80	No
8. Inadvertent emergency core cooling system actuation injection	60	Yes
9. Operational basis earthquake (20 earthquakes of 20 cycles each)	400	No
10. Excessive feedwater flow	30	No
11. RCS Cold Overpressurization	10	No
Emergency Condition Transients		
1. Small loss of coolant accident	5	Yes
2. Small steam line break	5	No
3. Complete loss of flow	5	Yes
Faulted Condition Transients		
1. Main reactor coolant pipe break (large loss of coolant accident)	1	No
2. Large steam line break	1	No
3. Feedwater line break	1	No
4. Reactor coolant pump locked rotor	1	No
5. Control rod ejection	1	No

Table 2.2.6-1 List of Design Basis NSSS Design Transients (Continued)

Transient Description	Number of Occurrences[a]	Revised for SPU
Faulted Condition Transients (continued)		
6. Steam generator tube rupture (included under upset conditions, reactor trip from full power with safety injection)	1	No
7. Safe shutdown earthquake	1	No

Notes:

a. Number of occurrences remains unchanged from the existing design basis.

b. Fluctuations related to the pressurizer insurge/outsurge are impacted. Nominal RCS pressure and temperature steady state fluctuations remain unchanged.

2.2.7 Bottom Mounted Instrumentation

2.2.7.1 Regulatory Evaluation

For BMI, NRC review standard RS-001 does not explicitly call out the SRP or any other guidance documentation. The DNC review focused on the effects of the proposed SPU on the structural integrity of the BMI components and their continued functionality, including the capability to maintain integrity of the RCPB, and withstand any adverse dynamic loads under the maximum pressures and temperatures associated with the SPU.

The acceptance criteria are based on 10 CFR 50 Part 55a and:

- GDC-1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed
- GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions
- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents
- GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture

MPS3 Current Licensing Basis

As noted in FSAR Section 3.1, the MPS3 design bases are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

The adequacy of the MPS3 design relative to conformance to:

- 10 CFR 50.55(a) is described in FSAR Section 5.2.1.1, Compliance with 10 CFR 50.55(a). RCS components are designed and fabricated in accordance with 10 CFR 50.55a. The actual addenda of the ASME Code applied in the original design of each component are listed in FSAR Table 5.2-1. FSAR Table 3.2-1 lists instrumentation and conduit tubes for the BMI as being constructed to the requirements of the ASME B&PV Code, Section III, Class 1.
- GDC-1, Quality Standards and Records, is described in FSAR Section 3.1.2.1.

  SSCs important to safety are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

  Quality standards applicable to safety related SSCs are generally contained in codes such as the ASME Boiler and Pressure Vessel Code. The applicability of these codes is specifically identified throughout the FSAR and is summarized in FSAR Section 3.2.5. FSAR Chapter 17 provides direct reference to the Quality Assurance Program established to provide assurance that safety related SSCs satisfactorily perform their intended safety functions. The procedures for generating and maintaining appropriate design, fabrication, erection, and testing records are contained within the referenced documents.

- GDC-2, Design Bases for Protection Against Natural Phenomena, is described in FSAR Section 3.1.2.2.

  Those features of plant facilities that are essential to the prevention of accidents that could affect the public health and safety or to the mitigation of accident consequences are designed to:

  1. Quality standards that reflect the importance of the function to be performed. Approved design codes are used when appropriate to the nuclear application.

  2. Performance standards that enable the facility to withstand, without loss of the capability to protect the public, the additional forces imposed by the most severe earthquake, flooding condition, wind, ice, or other natural phenomena for the site, and credible combinations of the effects of normal and accident conditions with the effects of the natural phenomena.

  Features of the facility essential to accident prevention and mitigation of accident consequences, which are designed to withstand the effects of natural phenomena, include the reactor coolant pressure boundary and containment barriers.

  All piping, components, and supporting structures of the reactor and safety related systems are designed to withstand a specified seismic disturbance and credible combinations of effects of normal and accident conditions coincident with the effects of natural phenomena. Plant design criteria specify that there is to be no loss of function of such equipment in the event of the safe shutdown earthquake (SSE) ground acceleration acting in the horizontal and vertical directions simultaneously. The dynamic response of Seismic Category I structures to ground acceleration, based on an envelope of characteristics of the site foundation soils and on the critical damping of the foundation and structures, is included in the design analysis.

  Design of structures for protection against natural phenomena is described in FSAR Section 3.8. Safety related structures have sufficient capacity to accept a combination of normal operating loads, functional loads due to the DBA, and the loadings imposed by the maximum wind velocity, or those due to the SSE, whichever is the larger.

- GDC-4, Environmental and Missile Design Bases, is described in FSAR Section 3.1.2.4.

  SSCs important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

SSCs important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in the FSAR Section 3.2.5.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the SSCs important to safety are designed.

- GDC-14, Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.14

  The RCS boundary is designed to accommodate the system pressures and temperatures attained under all modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits (FSAR Section 3.9). RCPB materials, selection, and fabrication techniques ensure a low probability of gross rupture or abnormal leakage.

  In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions, such as seismic and pipe rupture, as discussed in FSAR Sections 3.6 and 3.7.

  The RCS boundary has provisions for inspection, testing, and surveillance of critical areas to assess the structural and leak tight integrity (FSAR Section 5.2).

FSAR Sections 3.9.N.5.1 and 7.7.1.9.2 state in part that there are reactor vessel bottom instrumentation columns which carry the retractable, cold worked stainless steel flux thimbles that are pushed upward into the reactor core. Conduits extend from the bottom of the RV down through the concrete shield area and up to a thimble seal table. The thimbles are closed at the leading ends, are dry inside, and serve as the pressure barrier between the reactor water pressure and the containment atmosphere. Mechanical seals between the retractable thimbles and conduits are provided at the seal table. During normal operation, the retractable thimbles are stationary. They can move out only during refueling or for maintenance. The flux thimbles are extracted downward from the core during refueling to avoid interference within the core.

As described in response to NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Nuclear Reactors” (letter dated September 9, 1988), incore thimble tube degradation is managed by performance of ECT during each refueling outage. In response to NRC Bulletin 2003-02, during the Spring 2004 refueling outage (3R09), DNC performed a 360-degree bare metal visual inspection on the 58 RPV lower-head BMI penetration nozzles. The results of the inspection were documented in a letter dated June 24, 2004. The letter indicated that no evidence of through-wall leakage was observed through any nozzle penetration during the bare-metal visual inspection.

The BMI was evaluated for continued acceptability to support plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.3B.1.2 and 3.0.3.2.13 are applicable to the BMI guide.

2.2.7.2 Technical Evaluation

2.2.7.2.1 Introduction

The evaluations of the MPS3 BMI presented herein assess the impact of the SPU on the structural integrity of the BMI. This assessment considers the thermal transients, maximum operating temperatures and pressures, and design basis accident displacements that would result from the proposed SPU operating conditions. The results of these evaluations show that the stresses in the BMI guide tubing for the SPU remain within the allowable limit.

The BMI consists of guide tubing, flux thimbles, retractable miniature flux detectors, and the seal table. The retractable miniature detectors are inserted into the flux thimbles, which enter the guide tubing at the seal table, pass through the tubing into the reactor vessel, through the lower internals instrument columns, and then into the fuel assemblies. Each detector provides axial flux distribution data along the center portion of a fuel assembly. These data are then processed to obtain a core flux map.

The guide tubing and flux thimbles serve as pressure barriers between the RCS and the containment atmosphere. At the seal table, the pressure boundary for the guide tubing and flux thimbles is maintained by compression fittings where one end of each guide tube has a compressed fitting connection. The other end of each guide tube is welded to the bottom penetration nozzle of the reactor vessel bottom head. The leading ends of the flux thimbles are closed and bullet-nosed.

The guide tubing material is ASME SA213 Type 304L stainless steel. The guide tubes are pressure boundary components designed to ASME Boiler and Pressure Vessel Code Section III, Code Class 1, sub-section NC specifications and the guide tubing is classified as Seismic Category I.   The flux thimble material is ASME SA213 Type 316L, cold drawn and heat treated. The seal table is a rectangular plate designed to ASME Section III, Class 1, subsection NF requirements. The reactor BMI system guide tubing is classified as Seismic Category I. The flux thimble for the BMI system is classified as Seismic Category II, since it is an instrument tube.

2.2.7.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The BMI guide tubing is designed to meet the ASME Boiler and Pressure Vessel Code, Section III, Class 1 criteria. However, per Subsection NB-3630, Par. D.1 of the Code, “Piping of 1 inch nominal pipe size or less which has been classified as Class 1 in the design specification may be designed in accordance with the design requirements of Subsection NC.” In 1985, Stone and Webster performed an evaluation (referred to in the remainder of this LR section as the “initial evaluation”) which confirmed the structural acceptability of the BMI tubing, nozzles, valves, compression fittings and supports of MPS3. The load combination and allowable stress limits used in the SPU evaluation are the same as those used in the initial evaluation. A flux thimble is classified as an instrument tube, so it is outside the jurisdiction of the ASME Code per NA-1130(c). The flux thimbles are qualified as part of the BMI guide tubing, and as such, no separate qualification of the flux thimbles is needed. The weight of the flux thimbles is considered in the qualification of the BMI guide tubing.

The stress due to SSE anchor movements was not included in the initial evaluation. The SSE anchor movement stress is conservatively estimated in this calculation as 10 percent of the total stress minus the pressure stress. The revised Equation 9 (Faulted) stress includes the estimated stress due to SSE anchor movements.

The following sets of input parameters were considered in the evaluation for the SPU:

- Nuclear Steam Supply System (NSSS) Parameters for 3666 MWt NSSS Power in Table 1-1, Section 1.1, Nuclear Steam Supply System Parameters
- NSSS design transients in Section 2.2.6, NSSS Design Transients
- Displacements at the bottom of the reactor vessel head during a LOCA
- Initial evaluation

The SPU evaluation verifies no changes have been made to the facility that would invalidate the support stiffness values determined in the previous study and then utilizes the SPU operating parameters (Table 1-1 of Section 1.1, Nuclear Steam Supply System Parameters) to confirm acceptability under SPU conditions.

2.2.7.2.3 Description of Analyses and Evaluations

Three aspects of BMI guide tubing qualification are potentially affected by SPU changes and are therefore evaluated. They are:

3. Pressure increase during transients.
4. Temperature increase during transients, and the increased normal operating core inlet temperature for Table 1-1.
5. Reactor vessel bottom dome displacements during a LOCA.

The BMI guide tubing was originally qualified for 2500 psia and a reactor coolant temperature of 650°F within the reactor vessel and a temperature of 560°F between the base of the RV and the thermal shroud. The maximum temperature of the guide tube at the seal table is 150°F during normal conditions (Reference 4) and 267°F during a LOCA (Reference 3). Since the component weights and seismic loadings are unchanged for the SPU, the stresses due to dead weight, operating basis earthquake (OBE), and safe shutdown earthquake (SSE) seismic loadings remain unchanged.

Equations 8 through 11 from ASME B&PV Code Section III, Class I, Subsection NC-3650 are re-evaluated for the above three areas of interest. A new pressure stress value is calculated. A new pressure stress value is calculated at a pressure 2850 psia, which bounds all analyzed pressure transients. This pressure value is 14 percent higher than the previously qualified value of 2500 psia. A new temperature stress value is calculated at a temperature of 609.4°F, which bounds all analyzed transient temperatures. This temperature is a 8.8 percent higher than the previously qualified value of 560°F. The new displacement values are bounded by the displacement values of the initial evaluation, thus the stresses due to the displacement are also bounded by the initial site evaluation values. The stresses due to seismic and LOCA are combined using the square root sum of the squares (SRSS) method. The revised total stress values of Equations 8 through 11 are then compared with the respective allowable stress value for each condition.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

The BMI system components are included within the scope of license renewal as identified in the NRC License Renewal SER for MPS3, NUREG-1838, sections 2.3B.1.1 and 2.3B.1.2. As discussed in SER section 3.0.3.2.13, under "Thimble Tube Inspection," BMI components are subject to aging management programs which have been found acceptable by the NRC in NUREG-1838 for the extended period of operation of MPS3. The proposed SPU does not add new materials or components to the BMI system. Therefore, there are no unevaluated material changes to the BMI system with respect to license renewal. The potential effects of operational parameters on the BMI system are already subject to aging management programs. Thus, no new aging effects requiring management are identified.

2.2.7.2.4 Results

As shown in Table 2.2.7-1 and 2.2.7-2, the results of evaluations of the proposed SPU operating conditions indicate that the stresses in the BMI guide tubing remain within the allowable limit. Part A evaluates one of the shortest guide tubes, and Part B evaluates one of the longest guide tubes. Note that the Part B Equation 10 (Upset) stress is higher than the allowable stress, however, since the Equation 11 (Upset) stress is lower than the allowable stress, this is acceptable, per ASME Boiler and Pressure Vessel Code, Section III, Paragraph NC-3650. Therefore, the maximum stress ratio for the actual-to-allowable stress is 83 percent, with a minimum stress margin of 17 percent.

2.2.7.3 Conclusion

DNC has reviewed the assessment of the effects of the proposed SPU on the In-core Bottom Mounted Instrumentation and has determined that it has adequately accounted for the effects of changes in plant conditions associated with the proposed SPU on the design of the BMI. DNC concludes that the BMI will maintain its structural integrity under the operating conditions of the proposed SPU. DNC further concludes that the BMI will continue to meet the requirements of 10 CFR 50.55a and GDC-1, GDC-2, GDC-4 and GDC-14 following implementation of the SPU. Therefore, DNC finds the SPU acceptable with respect to the BMI.

2.2.7.4 References

1. ASME Boiler and Pressure Vessel Code, Section III, 1971 Edition, up to and including Summer 1973 Addendum.

2. ASME Boiler and Pressure Vessel Code, Section III, 1980 Edition, up to and including Summer 1982 Addendum.

3. ERC 25212-ER-07-0006 Rev. 2, "MP3 Uprate Post-LOCA Sump Fluid Temperatures," 2/20/07.

4. SP-M3-EE-0333, Rev. 3 “Specification for Millstone Unit 3 - Environmental Conditions for Equipment Qualification”

Table 2.2.7-1
SPU Stress Summary of ASME III Code Class 1 Equations 8 through 11 (Part A)

Equation No.	Stress (psi)	Allowable Stress (psi)	Ratio (Actual/Allowable)
8 (Design)	5968	13700	0.44
9 (Upset)	12493	16440	0.76
9 (Faulted)	14368	32880	0.44
10 (Upset)	22967	23050	1.00[1]
11 (Upset)	26291	36750	0.72

1. Per ASME Code, Paragraph NC-3650, the requirements of either equation 10 or equation 11 must be met.

Table 2.2.7-2
SPU Stress Summary of ASME III Code Class 1 Equations 8 through 11 (Part B)

Equation No.	Stress (psi)	Allowable Stress (psi)	Ratio (Actual/Allowable)
8 (Design)	5792	13700	0.42
9 (Upset)	13157	16440	0.80
9 (Faulted)	14796	32880	0.45
10 (Upset)	27346	23050	1.19[1]
11 (Upset)	30581	36750	0.83

1. Per ASME Code, Paragraph NC-3650, the requirements of either equation 10 or equation 11 must be met.

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

2.3.1.1 Regulatory Evaluation

Environmental qualification (EQ) of electrical equipment involves demonstrating that the equipment is capable of performing its safety function under significant environmental stresses which could result from design bases accidents (DBAs). The DNC review of the EQ program focused on the effects of the proposed SPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, anticipated operational occurrences, and accidents. The DNC review was conducted to ensure that the electrical equipment will continue to be capable of performing its safety functions following implementation of the proposed SPU.

The acceptance criteria for environmental qualification of electrical equipment are based on 10 CFR 50.49, “Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants”, which sets forth requirements for the environmental qualification of electrical equipment important to safety that is located in a harsh environment.

Specific review criteria are contained in SRP Section 3.11 and guidance is provided in Matrix 3 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 3.11, Rev. 2.

MPS3 took 2 exceptions to SRP Section 3.11, Rev. 2. They are as follows:

- FSAR Section 3.11 does not address mechanical equipment qualification.
- NUREG-0588 methodologies are not strictly followed.

These exceptions are addressed in special reports for both EEQ and Mechanical Equipment Qualification (MEQ), identified in FSAR Table 1.7-4, that were submitted to the NRC to provide additional information not addressed in FSAR Section 3.11. The EQ report addressed MPS3 compliance with NUREG-0588 and related details of the EEQ program. The MEQ report addressed review of environmental issues for seals and other non-metallic parts used in safety related mechanical equipment. The components identified in these reports have been included in the plant maintenance program. The NRC review concluded in SER Supplement 4 (NUREG-1031) that this information was acceptable. The EQ program was approved by the NRC in SER Supplement 5.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Additional details that define the Licensing Basis for safety-related electrical equipment qualification are described in the FSAR Section 3.11. The EQ Program complies with

10 CFR 50.49. The EQ program ensures the continued qualification of equipment that must function during and following design conditions postulated for design basis accidents and the post-accident duration.

In addition to the evaluation described above, the EQ program was evaluated for continued acceptability to support plant license renewal. NUREG-1838, “Safety Evaluation Report to the License Renewal of Millstone Power Station, Units 2 and 3”, dated August 1, 2005, documents the results of the review. NUREG-1838, Section 4.4 of the License Renewal is applicable to the EQ program.

2.3.1.2 Technical Evaluation

2.3.1.2.1 Introduction

Safety-related structures, systems and components at MPS3 are designed for environmental events as described in FSAR Sections 3.10 and 3.11. FSAR Section 3.10 provides the details regarding seismic qualification of safety related mechanical, structural, instrumentation and electrical equipment. FSAR Section 3.11 provides details regarding environmental qualification of safety related electrical equipment.

Design Specification SP-M3-EE-0333 is the sole source of EQ environmental data used for equipment qualification. However, existing information in FSAR Section 3.11 remains intact as an historical document, but will not be updated in the future.

As described in FSAR Section 3.11, the constituent parts of the EQ Program include the program basis, verification of equipment operability during and following exposure to plant environmental conditions, and proper installation and maintenance of equipment in the plant. These elements are controlled through a set of administrative documents consisting of a program description, implementing procedures, and reference documents. The documents are retrievable through the Station’s Electronic Document Management System (EDMS). The Master Equipment List (MEL) includes the equipment to which the environmental requirements of 10 CFR 50.49 are applied. This MEL is stored on a controlled electronic database in which the Equipment Qualification Master List (EQML) is a subset.

Program output is documented in Equipment Qualification Records (EQRs) that supports the qualification of equipment. These documents provide the auditable bases and evidence, which demonstrates that MPS3 is compliant with 10 CFR 50.49. EQRs utilize two main sources of design input – Test Report Assessments (TRAs), which are design calculations, and an Environmental Design Specification, SP-M3-EE-0333, Environmental Conditions for Equipment Qualification.

Electrical safety related equipment and associated commodities, which are located in a harsh environment zones as defined by Environmental Design Specification, are on the EQML database. The MPS3 EQML contains the following classifications of EQ equipment and associated commodities: 1) safety-related electrical equipment, 2) non safety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions, and 3) certain post-accident monitoring equipment. Equipment Qualification Records, (EQRs) are also electronically linked to the MEL.

MPS3 is divided into various environmental zones. The limiting environmental conditions for normal, accident, and post-accident operation are used for qualifying the equipment within these zones.

2.3.1.2.2 Description of Analyses and Evaluations

The environmental qualification of electrical equipment is performed for the components identified on the EQML. The existing equipment qualification parameters compared to the SPU parameter values.

The environmental parameters for both normal operation (including anticipated operational occurrences) and design basis accidents are temperature, pressure, radiation dose, humidity, spray chemistry and submergence.

Transient temperatures associated with anticipated operational occurrences, such as turbine trips or the loss of ventilation system, could increase slightly as a result of SPU but will have no impact on equipment qualification. The time weighted average operational temperatures made over the remaining 20 years would not be changed by the short temperature spikes associated with these anticipated transients and the time weighted average temperature would be bounded, with margin, by the building normal design temperatures used for equipment qualification.

The peak temperature values for the design basis accidents bound the temperature transients of the anticipated operational occurrences.

The qualified life of equipment is a function mainly of the temperature, and in some cases, the radiation dose environment. The evaluation of the qualified life, for the SPU, consists of comparing the normal operating temperature and radiation dose basis under current conditions. If the temperature or radiation dose for SPU operation does not change the current conditions, the qualified life of the equipment is not impacted. For equipment that has its qualified life based on specific local temperature or radiation monitoring data, the SPU operation impact will be monitored during SPU operation. Temperature monitoring data is collected on the plant computer using the Temperature Monitoring System (TMS) and will continue during SPU operation.

Radiation dose qualification is based on the sum of the normal operational dose plus the accident dose. SPU operation increases the total integrated dose (TID) to components inside containment and outside containment. The dose from airborne activity includes beta radiation. The equipment qualification evaluation compared the SPU total integrated dose to the component qualification dose, and the margin between the qualification dose and the SPU dose was determined.

The total accident dose includes both gamma and beta contributions. If the radiation qualification dose did not bound the total gamma plus beta dose, the exposed equipment was evaluated. Credit was taken for a reduction in the beta dose by considering the shielding provided by equipment cases/enclosures, conduit, and cable jackets.

Power uprates will typically increase the radioactivity level in the core by the percentage of the uprate. The radiation source terms in equipment/structures containing radioactive fluids, and the corresponding radiation zone doses, will increase for the uprate. Additional factors that impact the equilibrium core inventory and consequently, the estimated dose, are fuel enrichment and burnup.

The current normal operation radiation doses used for radiological environmental qualification at MPS3 are based on design considerations and source terms corresponding to a core power level of 3636 MWt, 1 percent fuel defects, and a traditional one-year fuel cycle length. Integrated doses are based on 40 years of normal operation.

The impact of SPU on the normal operation radiation environment used for equipment qualification is determined by using recent survey data which reflects MPS3 operation at full power, with an 18 month fuel cycle, and by utilizing the assessment provided in Section 2.10.1, Occupational and Public Radiation Doses, regarding impact of the SPU on normal operation radiation levels.

This assessment is used to verify or update as necessary, the dose rate values currently utilized to develop the 40 year integrated dose, taking into consideration an increased capacity factor from the previously used 0.8, to 1.0, operation at the current power level for the past twenty years, and operation at the SPU power level for the remaining 20 years.

The SPU core inventory is based on a core power level of 3723 MWt which (includes 2 percent margin for power uncertainty) and an 18 month fuel cycle. The impact of SPU on the post-accident gamma and beta environmental dose estimates provided for the environmental zones is evaluated utilizing scaling factors that are based on a comparison of the accident source terms developed based on the core inventory used to develop the original post-accident environmental doses, to the corresponding accident source terms developed using the SPU core inventory. Since the relative abundance of each isotope and the average gamma energy of each isotope are the key parameters that affect direct exposure, having a scaling factor that addresses the change in these parameters is sufficient to assess the radiological impact of SPU and fuel cycle length.

The referenced SPU dose scaling factors are based on TID 14844 source terms and applied to current post-accident environmental dose estimates to establish the SPU environmental levels. It is noted that although MPS3 has been approved for the implementation of alternative source terms for post accident dose assessments associated with the site boundary and control room, the SPU assessment supporting equipment qualification is based on TID 14844 source terms. This approach is acceptable based on Section 1.3.5 of RG 1.183 which indicates that though equipment qualification analyses impacted by plant modifications should be updated to address the impacts, no plant modification is required to address the impact of the difference in source term characteristics (i.e., AST vs. TID 14844) on environmental doses.

The estimated increase in radiation levels, reflect, in addition to the SPU power level and 18 month fuel cycle, the use of current computer codes, methodology and nuclear data in developing the uprated core inventory (vs. the methodology, computer tools and nuclear data used in the development of the original licensing basis core inventory). As a result, the calculated SPU dose scaling factor values are higher than the core power ratio.

The QA Category 1 computer codes used to support the assessment of impact of the SPU on radiation environments include industry code ORIGEN (used to develop the core inventory), and S&W Codes PERC2 and SW-QAD-CGGP (used to develop the SPU scaling factors).

The referenced computer codes have been used extensively, and the results accepted by NRC, for numerous nuclear power plant licensing applications

Inside Containment:

Design basis accident conditions for equipment qualification inside containment are the results of the loss of coolant accident (LOCA) and main steam line break (MSLB) as described in Section 2.6.1, Primary Containment Functional Design." The accident temperature and pressure vs. time profiles for SPU conditions are compared to the current accident temperature and pressure profiles that are the basis for the equipment qualification.

The post accident operability time (PAOT) was reviewed using the SPU temperature vs. time profile overlaid on the accident qualification profile with respect to long term aging.

The SPU gamma dose scaling factor is the ratio of the 1-year integrated gamma energy releases for the post-LOCA containment airborne source weighted by the gamma flux to dose rate conversion factors per energy group calculated with the uprated core activities vs. the weighted energy releases calculated with the currently analyzed core activities.

The SPU beta dose scaling factors are developed utilizing the relative integrated doses versus time from a semi-infinite cloud model based on the post-LOCA containment airborne source. The SPU beta scaling factor is a ratio of the 1-year integrated beta dose calculated with the SPU core divided by the beta dose calculated with the currently analyzed core activities.

Additional environmental parameters of humidity, spray water chemistry and submergence for SPU operation were also evaluated to the current SPU conditions.

Outside Containment:

The currently analyzed and the SPU core inventories are utilized to develop the post-LOCA energy release rates and gamma energy releases per energy group vs. time, for containment atmosphere inside containment, containment atmosphere in piping outside containment, sump water, pressurized recirculating fluid, and a "halogen only" release to account for buildup on filters and for condensate. In addition a gap release per energy group vs. time is developed to account for zones where the environmental dose is based on a fuel handling accident.

For the "unshielded" case, the factor impact on post-accident integrated gamma doses was estimated by rationing the gamma energy release weighted by the flux to dose rate conversion factor, as a function of time, for the SPU power level, to the corresponding weighted source terms based on the current power level. To address the fact that outside containment the sources are contained, the "unshielded" values included the shielding effect of a pipe wall thickness associated with a 2-inch nominal diameter pipe. This insured that the results were not skewed by photons at energies less than 25 keV which will be substantially attenuated by any piping sources.

To evaluate the impact of SPU on post-LOCA gamma doses (vs. time) in areas that are "shielded," the current as well as SPU source terms discussed above were weighted by the concrete reduction factors for each energy group.

The concrete reduction factors for 1 and 3 feet of concrete were used to provide a basis for comparison of the post LOCA spectrum hardness of source terms, with respect to time, for both original design and SPU cases, for lightly shielded and heavily shielded cases.

Since the SPU gamma dose scaling factors vary with radiation source, time, as well as shielding, the one year integrated SPU LOCA dose scaling factors developed and utilized varied from 1.02 (containment atmosphere) to a maximum of 1.20 (sump water). The SPU LOCA one year integrated airborne beta dose scaling factor is 1.01. For locations in the fuel building where the post accident dose is based on the FHA, the one year SPU FHA gamma and beta dose scaling factors are 1.01 and 1.14 respectively.

The above scaling factor approach was not utilized to develop the dose contribution due to the post accident ventilation filters (i.e., SLCRS, Auxiliary building and control room filters), and the airborne dose due to leakage which are based on the AST transport models/activity accumulation developed as part of the site boundary and control room LOCA dose consequence calculation, and consequently reflect AST.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal Safety Evaluation Report (SER) for the EQ Program for electrical equipment. As stated in Section 2.3.1.1, the EQ Program is within the scope of License Renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation. Thus, SPU has no impact on the EQ program.

2.3.1.2.3 Results

2.3.1.2.3.1 Inside Containment

Normal Operation

The normal operating temperature for equipment qualified life used a maximum design temperature of 120°F. This did not change for SPU operation. Therefore, the qualified life of equipment based on this temperature is not changed by SPU operation. (Section 2.7.7, Other Ventilation Systems (Containment))

However, for certain components, the EQ documentation for the 40 year qualification indicates credit is taken for local area temperatures that are less than the design temperature.

MPS3 local area temperature monitors, which are read and alarmed on a computer terminal in the control room, provide justification for the lower or higher temperatures that are used for equipment qualification, and are documented within the individual equipment EQRs.

Continued monitoring of these local area temperatures during SPU operation will identify any impacts. Components with qualification less than 40 years, based on the building design temperature, have an established replacement schedule. These replacement schedules have not been impacted since the normal operation maximum temperature has not changed.

The current containment normal operation pressure and humidity are not changed by SPU operation; therefore, there is no effect on qualified life.

The normal radiation level in the Containment increased, however, the equipment has been determined to remain qualified for SPU conditions.

Accident Conditions

The SPU peak accident temperature inside containment, as shown in Figure 2.3.1-1, is bounded by the current EQ accident profile used for the equipment qualification. However, the SPU profile has higher temperatures between 1800 seconds and 20,000 seconds. To ensure that the SPU profile is bounded by equipment qualification test profiles, a comparison to the SPU profile was performed for all EQ equipment qualified in containment. The results of this comparison showed that all equipment was bounded by the tested profiles and therefore unaffected by the SPU transient.

The current post accident profile is identical to the SPU profile with respect to long term aging. Therefore the post accident operability time (PAOT) has no adverse affect on equipment qualification.

As shown in Figure 2.3.1-2, the SPU accident peak pressure is shown to be bounded by the current EQ qualification pressure.

However, the SPU profile has higher pressure between 1800 seconds and 20,000 seconds. This does not affect equipment qualification.

The TID (40 year normal plus accident, gamma and beta) in the Containment is conservatively established at 2.4E8 Rads for current conditions. This dose envelopes the post-LOCA total integrated dose (40 year plus accident) in the Containment at SPU conditions.

The beta dose has been evaluated with respect to the component's inherent shielding and/or its configuration that limits beta exposure. The equipment has been determined to remain qualified for SPU conditions.

The accident humidity of 100 percent is not changed by SPU operation.

The sump pH value range as a result of a LOCA, has changed from 4.4–11.0 to 4.1–11.0, due to assumed changes in Boron concentrations. This increase has no impact on equipment qualification.

Following SPU, the submergence evaluation showed an increased from elevation -11 ft - 3 in. to -11 ft – 2 in. An evaluation revealed that this one inch increase in submergence has no impact, since all equipment is located above flood level.

2.3.1.2.3.2 Main Steam Valve Building (MSVB)

Normal Operation

Normal environmental plant operating conditions within the MSVB (i.e. temperature, pressure, humidity and radiation) did not change due to SPU.

Accident Conditions

The SPU accident temperature in the MSVB, following a MSLB increases from 500°F to 562.5°F. This increase of 62.5°F affects the following equipment located within zone MS-01: ASCO solenoid valves, NAMCo limit switches, Limitorque MOV's, Rosemount pressure transmitters, solenoids associated with the Sulzer MSIV's and ITT actuators. These qualification issues will be resolved prior to SPU implementation by performing additional evaluations.

The accident radiation in the MSVB has been updated to reflect the SPU conditions. The TID increased from 1.1E4 to 4.0E4 Rads. However, the equipment has been determined to remain qualified for SPU conditions.

The accident humidity of 100 percent is not changed and is not impacted by SPU operation.

The EQ peak pressure is not changed by SPU.

There is no change in flood elevation due to SPU operation.

2.3.1.2.3.3 Engineered Safety Features Building (ESF)

Normal Operation

Normal environmental plant operating conditions within the ESF (i.e. temperature, pressure, humidity and radiation) did not change due to SPU.

Accident Conditions

There is no change in accident temperature, pressure or humidity due to SPU operation (Section 2.5.1.3, Pipe Failures).

The accident radiation in the ESF has been updated to reflect the SPU conditions. The TID increased from 1.3E7 to 1.6E7 Rads. However, the equipment has been determined to remain qualified for SPU conditions. The increased radiation levels in ESF EQ Zones ES-01 and ES-07 may impact qualification requirements of equipment in those areas. These qualification issues will be resolved prior to SPU implementation.

There is no change in the accident flood elevation due to SPU operation.

2.3.1.2.3.4 Auxiliary Building (AUX)

Normal Operation

Except for the radiation level in the AUX building which has been updated for SPU, the normal operation environmental conditions (i.e., temperature, pressure and humidity) remain unchanged for SPU.

Accident Conditions

There is no change in accident temperature, pressure or humidity due to SPU operation (Section 2.5.1.3, Pipe Failures).

The accident radiation in the Auxiliary Building has been updated to reflect the SPU conditions. The TID increased from 1.7E7 to 3.0E7 Rads. However, the equipment has been determined to remain qualified for SPU conditions. The increased radiation levels in AUX building EQ Zones AB-19, AB-22, AB-24, and AB-31 may impact qualification requirements of equipment in those areas. These qualification issues will be resolved prior to SPU implementation.

There is no change in the accident flood elevation due to SPU operation.

2.3.1.2.3.5 Fuel Building (FB)

Normal Operation

Except for the radiation level in the FB which has been updated for SPU, normal environmental plant operating conditions (i.e., temperature, pressure and humidity) within the FB did not change due to SPU.

Accident Conditions

There is no change in accident temperature, pressure or humidity due to SPU operation (Section 2.5.1.3, Pipe Failures).

The accident radiation in the Fuel Building has been updated to reflect the SPU conditions. The TID increased from 5.9E4 to 6.4E5 Rads. However, the equipment has been determined to remain qualified for SPU conditions.

There is no change in the accident flood elevation due to SPU operation.

2.3.1.2.3.6 Hydrogen Recombiner Building (HR)

Normal Operation

Except for the radiation level in the HR building which has been updated for SPU, normal environmental plant operating conditions (i.e. temperature, pressure and humidity) within the HR building did not change due to SPU.

Accident Conditions

There is no change in accident temperature, pressure or humidity due to SPU operation (Section 2.5.1.3, Pipe Failures).

The accident radiation in the HR has been updated to reflect the SPU conditions. The TID increased from 9.2E5 to 9.4E5 Rads. However, the equipment has been determined to remain qualified for SPU conditions.

There is no change in the accident flood elevation due to SPU operation

2.3.1.2.3.7 Turbine Building

Normal Operation

Except for the radiation level in the Turbine building which has been updated for SPU, normal environmental plant operating conditions (i.e. temperature, pressure and humidity) within the Turbine Building did not change due to SPU.

Accident Conditions

The Turbine Building has been analyzed in the FSAR for equipment qualification and for barrier protection for the Control Room. The bounding temperature condition for HELB in the Turbine Building is the rupture of the main steam system. This condition has been previously evaluated for equipment qualification at 102 percent power. This previously performed temperature analysis is no longer bounding for SPU conditions. There are two component types listed in the EQML that are in the Turbine Building. These components identified on the EQML are part of the ATWS AMSAC, as shown on the FSAR Figure 10.3-1, and FSAR Section 7.8. The EQML will be revised to remove these components as they do not require environmental qualification. FSAR Table 3.6.5 lists two valves in the Turbine Building as essential for shutdown in the event of a HELB in the Auxiliary Building. Since there is no equipment in the Turbine Building requiring qualification for breaks in the Turbine Building, a revised temperature profile is not necessary.

The pressure for the Turbine Building, resulting from a main steam line break in the Turbine Building does not change for SPU.

No hazards analysis is necessary for the Turbine Building based on the discussion above since there is no safety related equipment in the building and no essential shutdown equipment that needs protection for HELBs in the Turbine Building.

The SPU TID, accident plus 40 years, remains mild for radiation, and therefore, does not impact equipment qualification.

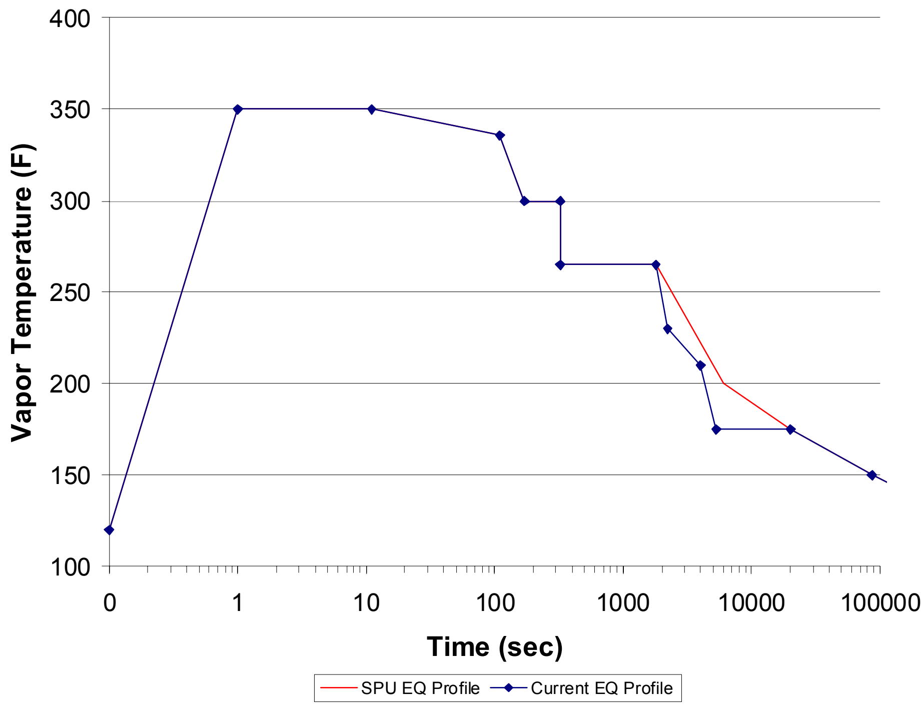
There is no change in the accident flood elevation due to SPU operation.

2.3.1.3 Conclusion

DNC has reviewed the affects of the proposed SPU on the EQ of electrical equipment and concludes that the evaluation has adequately addressed the effects of the proposed SPU on the environmental conditions for the qualification of electrical equipment.

Based on this evaluation, the electrical equipment will continue to meet the relevant requirements of 10 CFR 50.49 following implementation of the proposed SPU. The impact of minor environmental changes on the EQ program will be resolved prior to SPU implementation. Therefore, DNC finds the proposed SPU acceptable with respect to the environmental qualification of electrical equipment.

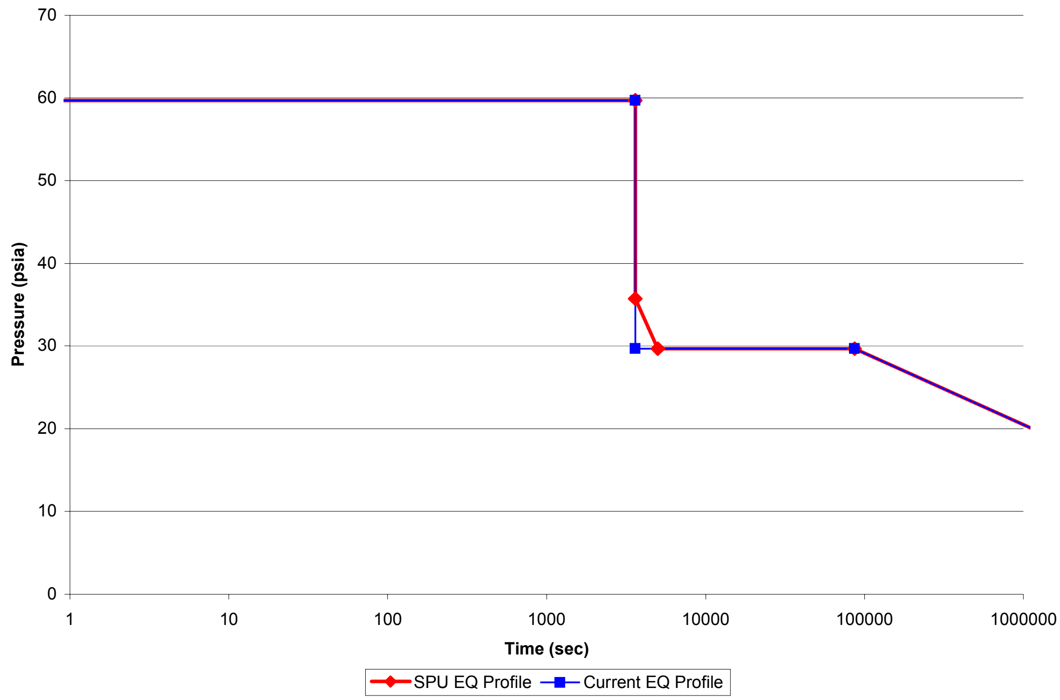
Figure 2.3.1-1
Containment Accident Temperature Profile



This overlay of the EQ temperature profile on the SPU accident profile shows that the peak temperature of the SPU is identical to the EQ profile. Therefore all EQ equipment inside the containment remains qualified for the SPU accident peak temperature condition.

The SPU temperature at 24 hours and beyond is bounded by the equipment qualification temperature. Therefore, the equipment remains qualified for post accident operating time.

Figure 2.3.1-2
SPU Accident Pressure Profile



There is a slight increase in the pressure profile for SPU from 30 to 35 psia between the 1800 seconds and 20,000 second. This has no affect on the qualification of the equipment since the tested conditions envelope the SPU peak pressure.

2.3.2 Offsite Power System

2.3.2.1 Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The DNC review covered the descriptive information, analyses, and referenced documents for the offsite power system; and the stability studies for the electrical transmission grid. The review focused on whether the loss of the nuclear unit, the largest operating unit on the grid, or the most critical transmission line will result in the LOOP to the plant following implementation of the proposed SPU. The acceptance criteria for the offsite power system are based on GDC-17.

Specific review criteria are contained in SRP Sections 8.1 and 8.2, and Appendix A to SRP, Section 8.2, Branch Technical Positions (BTPs) PSB-1 and ICSB-11, and guidance is provided in Matrix 3 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800), SRP Sections 8.1, Rev. 2, and 8.2, Rev. 3.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to conformance to:

- GDC-17 is described in the FSAR Section 3.1.2.17, General Design Criteria 17 - Electric Power Systems.

  Two connections to the offsite power system are provided. The preferred offsite connection is a backfeed through the main and normal station service transformers with the generator breaker open. The alternate offsite connection is through the reserve station service transformers. Each offsite source has 100 percent capacity for all emergency and normal loads during all phases of operation, plus the capacity to supply Millstone Unit 2 GDC-17 requirements through the NSST or RSST as an alternate offsite source for minimum post-accident loads.

Additional details that define the licensing basis are described in FSAR Sections 8.1 and 8.2, Offsite Power System.

The offsite power system was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.5 and 3.6 identify generic commodity groups that are applicable to the offsite power system.

2.3.2.2 Technical Evaluation

2.3.2.2.1 Introduction

The offsite power system and its components are discussed in the FSAR Sections 8.1.1, 8.1.2, 8.1.3, 8.2, and Figures 8.1-1 and 8.1-3. The offsite power system consists of the 345 kV switchyard, overhead tie-lines that connect from main transformers A and B high-voltage bushings to the switchyard, including associated motor operated disconnect switches 15G-3XA1-4 and 15G-3XB1-4. Also included are the overhead tie-line from reserve station service transformers A and B to the switchyard, including associated motor operated disconnect switches 15G-23SA1-4, 15G-23SB1-4, and 15G-18T-8. In addition, main transformers A and B, and reserve station service transformers A and B are included in the offsite power system.

The 345 kV switchyard is arranged in a breaker-and-a-half configuration. Its function is to interconnect the station output to the transmission grid and provide two separate and independent offsite power sources to the station via separate tie-lines and power transformers.

The function of the two three-phase, two winding main transformers is to provide a means to transmit the generator output power to the switchyard by stepping up the generator voltage from 24 kV (nominal) to the switchyard voltage of 345 kV. In addition, an immediate offsite power supply can be accomplished by backfeeding through the main transformers and normal station service transformers with the generator circuit breaker open.

The function of tie-lines is to deliver the station output power from the main transformers to the 345 kV switchyard. Also, the tie-lines provide two separate and electrically independent offsite power circuits to the station auxiliary loads.

The function of the two separate three-phase, three winding reserve station service transformers A and B is to step down the offsite voltage from 345 kV to 6.9 kV and 4.16 kV and power the auxiliary loads during start up, shutdown, and loss of station generating capacity, and when the normal station service transformers A and B are not available.

The function of the motor-operated disconnect switches 15G-3XA1-4, 15G-3XB1-4, 15G-23SA1-4, and 15G-23SB1-4 is to isolate the main transformers A and B and reserve station service transformers A and B from the 345 kV system.

Grid stability studies were performed to evaluate the impact of MPS3 on the reliability of the local 345 kV and ISO New England (ISO-NE) bulk power systems.

2.3.2.2.2 Description of Analyses and Evaluations

The offsite power system and its components were evaluated to ensure they are capable of performing their intended function at SPU conditions. The evaluation was based on the system's required design functions and attributes and upon a comparison between the existing equipment ratings and the anticipated operating requirements at SPU conditions.

An interconnect system impact study was performed to evaluate the impact of the MPS3 on the reliability of the local 345 kV and ISO-NE bulk power systems. The study was performed in accordance with DNC agreement with ISO-NE, including impacts in accordance with New

England Power Pool (NEPOOL) Reliability Standards and NEPOOL Minimum Interconnection Standards.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal safety evaluation report for offsite power system. As stated in Section 2.3.2.1 above, the switchyard interface components are within the scope of license renewal. SPU activities do not add any new passive components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with operation of the offsite power system at SPU conditions, and the SPU does not add any new passive or previously unevaluated components or materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.3.2.2.3 Results

2.3.2.2.3.1 Grid Stability

The transmission system is discussed in FSAR Sections 8.2.1 and 8.2.2. A system reliability impact study (SRIS) was performed to evaluate the impact of the MPS3 SPU on the reliability of the local 345 kV and ISO-NE bulk power systems.

The existing MPS3 generator is rated at 1354.7 MVA, 24kV, 60 hz, 0.925 pf, 1800 rpm @ 75 psig hydrogen pressure. It was originally analyzed for a gross electrical output rating of 1208 MW and 520 gross maximum lagging MVARS and no leading MVARS.

In 2004, re-analysis was performed to support turbine modifications to a gross power output rating of 1260 MW and 467 gross maximum lagging MVARs and no leading MVARs. For this increase in power output the generator excitation system was upgraded and a Power System Stabilizer was installed.

For MPS3 SPU the generator has been analyzed for a gross output power increase of 1276 MW (summer) and 1296 MW (winter) for a net output increase of 16 MW (summer) and 36 MW (winter). The reactive power output based on a power factor 0.957 is a maximum of 445 MVAR (summer) and 395 MVARs (winter) and no leading MVARs.

The station service loads at the SPU condition was modeled at 50 MW and 37 MVARs.

Thermal and voltage analyses were performed based on extreme weather load cases and stability analysis was performed on 2009 summer peak and light load cases with and without Connecticut Export. Pre-contigency and post-contingencies were evaluated with load flow analysis for each seasonal condition. This analysis involved an extensive examination of contingencies of local and cross-state transmission facilities located around the Millstone Station area. Key results provided in the study are as follows:

- The thermal analysis does not cause any significant thermal impact on the transmission facilities in New England.

- The voltage analysis also concluded there would be no significant adverse impact on the interconnect system. The minimum 345 kV and maximum of 362.25 kV voltages will continue to be maintained at Millstone.
- The stability analysis showed the grid to remain stable over all analyzed contingencies.
- The system would remain stable during faults on double circuit towers.
- Short circuit current magnitudes and breaker cleaning times were shown to be acceptable.
- Line out studies (including analysis with Unit 3 Severe Line Outage Detector (SLOD) considered) showed the interconnect system remains stable.
- Demonstrates system performance with and without the power uprate for pre-contigency and post-contingency voltages and line loading, and for dynamic response to system disturbances to verify that widespread or cascading interruptions to service do not result from these contingences.
- The loss of MPS3 or the loss of any other generating plant in the system does not result in cascading system outages and thus does not cause loss of offsite power to the units and the ability of the grid to supply the reactive support to the onsite power needs under all plant conditions
- Establishes that under transmission system “stressed” conditions; all line loadings analyzed remain within current ratings are contained within the system model consider transmission line sag due to loading (current, wind, ice, and ambient temperature).
- The ability of the grid to maintain the required 345 kV minimum switchyard voltage and provide the necessary reactive power to support of the onsite power requirements.

The increase in current across transmission lines due to the MPS3 power uprate will not change in electrical shock hazard. Transmission line rated voltage remain unchanged, and therefore required transmission line clearances remain unchanged. The study establishes that under transmission system “stressed” conditions; all line loadings analyzed remain within current ratings. The line ratings contained within the system model consider transmission line sag due to loading (current, wind, ice, and ambient temperature). The additional loading due to MPS3 does not decrease the required clearances established by the utilities, which operate the lines because the lines operate within their ratings. In general the clearances for transmission lines are based on the National Electric Safety Code (NESC).

MPS3 per its interconnect agreement will provide as required, additional reactive power based on the generators capabilities by reducing output power. Millstone Unit 2 maximum reactive capabilities are not affected and remain at 440 MVARS.

The studies have demonstrated that the steady state and dynamic performance of MPS3 at the power uprate conditions remains acceptable. The offsite power system will continue to meet the requirements of GDC-17 for MPS3 and MPS2 at the MPS3 power uprate conditions and provide the necessary power including reactive power to support the unit’s onsite system.

Therefore, the results of the power uprate study indicates the thermal, voltage, and stability performance is not degraded by implementation nor does it compromise the interrupting capabilities of offsite system equipment.

2.3.2.2.3.2 Offsite Power System Components

345 kV Switchyard

The 345 kV switchyard is discussed in FSAR Section 8.1.3. The equipment has been evaluated for SPU conditions. The equipment within the switchyard is not owned by DNC.

The 345 kV switchyard and distribution system were evaluated to ensure required functions are performed after the implementation of MPS3 uprate and, consequently, to ensure the functionality of the switchyard and its associated components affected by the power uprate. The evaluation determined that there are no changes required to the 345 kV switchyard equipment or associated components. The 345 kV switchyard equipment ratings were determined to bound the MPS3 SPU operating condition requirements.

The switchyard configuration has not changed due to MPS3 SPU; and with the generator circuit breaker open, it continues to provide a reliable offsite power supply path to the normal onsite distribution system through the main transformers and normal station service transformers. The reserve auxiliary transformers provide a second access circuit to the onsite distribution system. The separate circuits satisfy the independence and redundancy requirements of GDC-17.

Main Transformers A and B

The main transformers A and B are discussed in FSAR Sections 1.2.9, 1.3, 8.1, 8.1.7 and 8.2.2. The equipment has been evaluated for SPU conditions. The evaluation confirms that the two main transformers A and B existing design rating of 840 MVA at 65°C rise (with 12 coolers operating) envelopes the anticipated worst-case loading at SPU conditions. The worst-case loading on the main transformers occurs when the reserve station service transformers are supplying the station auxiliary loads and the unit is operating at full SPU. Refer to Table 2.3.2-1 for main transformer loading and design rating comparison.

Each transformer is protected by current differential (87TA, 87TB, 87NTA & 87NTB) relays. Operation of these relays depends on the associated current transformer (CT) ratios, which have not changed. Therefore, there is no impact to these relays due to SPU. Also, backup protection is provided by current differential (87T), which is not affected by an increase in unit output current due to SPU.

Operating at SPU does not affect the capability of back feeding from the 345 kV switchyard through the main transformers and normal station service transformers with the generator breaker open.

Tie-Lines

The tie-lines are discussed in FSAR Section 8.2.1. The equipment has been evaluated for SPU conditions. The evaluation indicates that the existing tie-lines between the main transformers A and B high voltage bushings and the 345 kV switchyard, as well as between the 345 kV switchyard and reserve station service transformers A and B, are adequate for operation at SPU conditions. The evaluation predicted the maximum operating temperature of the conductors determined adequacy of conductor clearances and materials with conductors operating at the maximum operating temperature. The evaluation determined that the increase in output ampacity will not raise the conductor temperatures above its 75°C rating, conductor clearances at maximum operating temperature meet industry standards, and materials will provide satisfactory performance at the maximum operating temperature.

MPS3 is in the process of replacing the 345 kV tie line polymer insulators and miscellaneous line hardware from the main transformers and reserve station service transformers to the switchyard that was identified during an inspection completed in 2005.

SPU will result in an increased current through the output tie lines to the switchyard; however, there will be no change in electric shock hazard. The industry-accepted ground clearance of 29 ft. (based on voltage) to meet the 5 mA electrostatic current (NESC Sections 232C1c and 232D1c) is exceeded, since the evaluation indicates that the lowest ground clearance in any span is 39.8 ft.

Tie-Line Protection

An evaluation indicates that the increase in plant auxiliary loads at SPU conditions does not adversely affect the existing reserve station service transformer tie-line protection; and requires no relay setting changes.

Reserve Station Service Transformers A and B

The reserve station service transformers A and B are discussed in FSAR Sections 8.1.4, 8.1.7, 8.2.2, and 8.3.1.1.1. The equipment has been evaluated for SPU conditions. The 4.16 kV and 6.9 kV buses are supplied from separate reserve station service transformers A and B, respectively. The load changes on the 4.16 kV buses as a result of SPU are bounded by the load values presently used in the existing analysis. Therefore, reserve station service transformer A does not require re-evaluation because the existing analysis includes conservative load values for the affected pump motors. The reserve station service transformer B, which is affected by reactor coolant pump brake horsepower load increases, has been evaluated to SPU conditions. The calculated worst-case reserve station service transformer B loading occurs when normal station service transformer B is out of service and the station auxiliary loads on the 6.9 kV bus are supplied only from reserve station service transformer B. The evaluation confirms that both the existing reserve station service transformers A and B maximum design ratings of 45 MVA and 50 MVA at 65°C, respectively, are adequate to support unit operation at SPU conditions. Refer to Table 2.3.2-2 and 2.3.2-3 for reserve station transformer loading and design rating comparison.

Motor Operated Disconnect Switches

The 345 kV main transformer motor-operated disconnect (MOD) switches 15G-3XA1-4 and 15G-3XB1-4 are vertical break with horizontal mounting rated at 3.0 kA continuous current. They are used to disconnect the two main transformers from the system under a dead bus connection. The 345 kV reserve station service transformer MOD switches 15G-23SA1-4 and 15G-23SB1-4 are vertical break with upright mounting rated at 2.0 kA continuous current. They are used to disconnect the two reserve station service transformers from the 345 kV system under a live bus connection. MOD switch 15G-18T-8, which is located in the 345 kV switchyard, is rated 2.0 kA continuous current and used to disconnect the circuit from the switchyard to the reserve station service transformers. The evaluation confirms that the anticipated worst case load current on the MOD switches are well within the continuous current design ratings.

As a result of the evaluations for SPU, it has been determined that the offsite power system will continue to have sufficient capacity and capability to supply power to all safety loads and other required equipment. Two separate and independent offsite power sources continue to be maintained in accordance with the MPS3 current licensing basis with respect to the requirements of GDC-17.

2.3.2.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the offsite power system and concludes that the evaluation has adequately accounted for the increased output on the offsite power system. The offsite power system will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-17 following implementation of the proposed SPU. Adequate physical and electrical separation exists and the offsite power system has the capacity and capability to supply power to all safety loads and other required equipment. DNC concludes that the impact of the proposed SPU on grid stability is insignificant. Therefore, DNC finds the proposed SPU is acceptable with respect to the offsite power system.

Table 2.3.2-1 Main Transformer Output Loading (No Station Auxiliary Loads Supplied From NSSTs)

MT A Output Load (Note 1)			MT B Output Load (Note 1)			MT Design Rating (Note 2)
MW	MVAR	MVA	MW	MVAR	MVA	MVA
644.4	103.4	652.6	649.8	103.9	658.1	630/840 @65°C (FOA)

Notes for Table 2.3.2-1:

1. The MT output loading is derived from load flow/voltage profile analysis.
2. The MT nameplate rating of 840 MVA at 65°C rise is with 12 coolers in operation.

Table 2.3.2-2 RSST-B Maximum Output Loading (X and Y Windings) (NSST B Out of Service)

Secondary Winding	Output Loading						Design Rating		Reference
	X-Winding			Y-Winding			X-Winding	Y-Winding	
	MW	MVAR	MVA	MW	MVAR	MVA	MVA	MVA	
Existing	16.09	7.64	17.81	20.72	10.43	23.20	15/20/25 MVA OA/FOA/ FOA @65°C	15/20/25 MVA OA/FOA/ FOA @65°C	Note 1
Existing+ SPU	16.91	7.46	18.48	21.59	10.13	23.85			Note 2
Increment	0.82	-0.18	0.67	0.87	-0.30	0.65			Note 3
Total Output Load	16.91	7.46	18.48	21.59	10.13	23.85	25@65°C	25@65°C	Note 2
Notes for Table 2.3.2-2 are shown after Table 2.3.2-3.									

Table 2.3.2-3 RSST-B Maximum Input Loading on the H Winding (NSST B Out Of Service)

Primary Winding	H- Winding			Design Rating	Reference
	MW	MVAR	MVA	MVA	
Existing	36.98	21.06	42.56	30/40/50 MVA OA/FOA/FOA @65°C	Note 1
SPU+Existing	38.69	20.77	43.91		Note 2
Increment	1.71	-0.29	1.35		Note 3
Total Input Load	38.69	20.77	43.91	50@65°C	Note 2

Notes for Table 2.3.2-2 and 2.3.2-3:

1. Existing loading is derived from load flow/voltage profile analysis. These values represent the present calculated loading on the transformer prior to SPU.
2. SPU+Existing loading are derived from load flow/voltage profile analysis. These values represent the total calculated loading on the transformer after SPU.
3. Increment loading is the difference between the Existing loading (Note 1) and SPU+Existing loading (Note 2). These values represent the additional loading on the transformer as a result of SPU.

2.3.3 AC Onsite Power System

2.3.3.1 Regulatory Evaluation

The alternating current (ac) onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to safety-related equipment. The DNC review covered the descriptive information, analyses, and referenced documents for the ac onsite power system.

The acceptance criteria for the ac onsite power system are based on:

- GDC-17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions.

Specific review criteria are contained in SRP Sections 8.1 and 8.3.1, and guidance is provided in Matrix 3 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” July 1981, SRP Sections 8.1, Rev. 2 and 8.3.1, Rev. 2. MPS3 took exception to SRP 8.3.1 (Rev. 2) Section II.4.f, compliance to NUREG/CR-0660. NUREG/CR-0660 is not addressed in the FSAR as required by SRP 8.3.1, Paragraph II.4.f. NUREG/CR-0660 considerations have been addressed in responses provided to NRC questions. Refer to the 430 series of questions - Question 430.58 through Question 430.134 for details. This NUREG is only applicable to the emergency diesel engine and its support systems as described in FSAR Section 9.5, Other Auxiliary Systems.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to conformance to the following:

- GDC-17 is described in the FSAR Section 3.1.2.17, Electric Power Systems (Criterion 17).

  Two connections to the offsite power system are provided. The preferred offsite connection is a backfeed through the main and normal station service transformers with the generator breaker open. The alternate offsite connection is through the reserve station service transformers. Each offsite source has 100 percent capacity for all emergency and normal loads during all phases of operation plus the capacity to supply Millstone Unit 2 GDC-17 requirements through the normal station service transformer or reserve station service transformer as an alternate offsite source for minimum post-accident loads.

  Two onsite power systems are provided. Each system has an emergency diesel generator. Each diesel generator has 100 percent capacity for the emergency loads in the event of the postulated accidents or required for reactor cooldown.

  The design of the electrical system (FSAR Chapter 8) conforms to Criterion 17.

Additional details that define the licensing basis are described in FSAR Sections 8.1.4, Onsite Electric System and 8.3.1, AC Power Systems.

The ac onsite power system was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005, defines the scope of license renewal. NUREG-1838 Sections 2.5 and 3.6 are applicable to the ac onsite power system.

2.3.3.2 Technical Evaluation

2.3.3.2.1 Introduction

The ac onsite power system and its components are discussed in the FSAR Sections 8.1.4 and 8.3. The ac onsite power system consists of normal station service transformers, the 6900 V, 4160 V, 480 V, 120 V systems, emergency diesel generators, associated buses, cables, electrical penetrations (where applicable), circuit breakers and protective relays. In addition, the main generator, generator circuit breaker and isolated phase bus duct are included in the ac onsite power system evaluations.

The function of the two three-phase, three-winding normal station service transformers (NSST) A and B is to provide the normal onsite source of power for station loads. During normal plant operation, power from the main generator is stepped down from 22.8 kV to 6.9 kV and 4.16 kV to supply the onsite ac electrical distribution system normal and Class 1E loads.

The function of the 6.9 kV system is to supply power for operation of large non-class 1E motor loads within acceptable design limits.

The function of the 4.16 kV system is to provide power for the operation of all the units' non-class 1E and class 1E loads (except 6.9 kV) within acceptable design limits.

The function of the 480 V system is to supply low voltage power for the operation and control of non-class 1E and class 1E loads, through load centers and motor control centers within acceptable design limits.

The function of the 120 V ac vital power system is to provide regulated and uninterruptible power to vital controls and instrument loads. The 120 V ac non-vital power system provides a continuous source of regulated power to non-vital loads and the plant computer.

The function of the two emergency diesel generators is to provide emergency power to the class 1E 4.16 kV emergency buses 34C (Train A) and 34D (Train B) to safely shutdown the reactor and maintain it in a safe condition for any accident coincident with loss of offsite power.

The function of the main generator is to provide a means of converting the mechanical energy of the main turbine into a supply of regulated and usable electricity. The generator output is delivered at 24 kV to the main transformers A & B and normal station service transformers A and B through isolated phase bus duct and the generator circuit breaker.

The function of the isolated phase bus duct is to conduct electrical power from the main generator to the main transformers and normal station service transformers.

The function of the generator circuit breaker is to synchronize the main generator to the offsite system. It automatically operates only on turbine, reactor, and generator trips and can be manually operated from the control room.

2.3.3.2.2 Description of Analysis and Evaluations

The ac onsite power system and its components were evaluated to ensure they are capable of performing their intended function at SPU conditions. The evaluation is based on the system's required design functions and attributes, and upon a comparison between the existing equipment ratings and the anticipated operating requirements at SPU conditions. The SPU requires that equipment operate at service conditions different from currently evaluated. To determine the impact of SPU operation on the ac onsite power system, bus loading was developed to represent the existing plant loading conditions using values from the existing load flow calculation. Worst-case load values from the calculation were used in performing the evaluation. Updated load flow/voltage profile analyses that include load changes as a result of SPU conditions were performed. The results of these analyses are discussed in the following sections and are used to ensure that the systems/equipment is capable of performing their intended functions and form the bases for the ac onsite power system evaluations.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal safety evaluation report for the ac onsite power system. As stated in Section 2.3.3.1, the ac onsite power system is within the scope of license renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with operation of the ac onsite power system at SPU conditions and the SPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.3.3.2.3 Results

Normal Station Service Transformers

The NSSTs are discussed in FSAR Section 8.3.1.1.1. The equipment has been evaluated for SPU conditions. The SPU load changes on NSST A for the 4.16 kV system are within the brake horsepower load values provided in the existing load flow/voltage profile analysis. The worst-case reactor coolant pump brake horsepower load increases the total loading on NSST B to 43.64 MVA, which remains within the transformer design rating of 50 MVA @ 65°C. Table 2.3.3-1 provides the SPU impact on NSST B. Refer to Section 2.2.2.6, Reactor Coolant Pumps and Supports, for a discussion of the reactor coolant pump motor brake horsepower SPU impact.

6.9 kV System

The 6.9 kV system is discussed in FSAR Section 8.3.1.1.1. The evaluation of the 6.9 kV system at SPU conditions confirms the following:

Switchgear Buses and Circuit Breakers, Circular Non-segregated Phase Bus Duct, Rectangular Non-segregated Phase Bus Duct and interconnecting cables

- The calculated worst case continuous current for each 6.9 kV switchgear bus, incoming circuit breaker and rectangular non-segregated phase bus duct, during maximum full load at SPU conditions, is less than the equipment design ratings, as indicated in Table 2.3.3-2. Therefore, the SPU loading requirements of switchgear buses, incoming circuit breakers and rectangular non-segregated phase bus ducts are within the equipment design ratings.
- The calculated loading for the circular non-segregated phase bus duct at SPU conditions is bounded by the equipment ratings.
- The calculated loading for the interconnecting cables between the circular and rectangular non-segregated phase bus at SPU conditions is within cable ampacity rating.
- The calculated full load current for each reactor coolant pump motor during maximum full load at SPU conditions is less than the feeder circuit breaker design rating. Therefore, the SPU loading requirements for motor feeder breakers are bounded by equipment design ratings.
- There are no changes or modifications to the 6.9 kV system that would increase the short circuit current at SPU conditions. Therefore, the SPU fault duty requirements of the 6.9 kV switchgear buses and breakers are bounded by the existing analysis.

System Voltage Level

Motor terminal voltage for running 6.9 kV motors at SPU conditions during steady state maximum full load conditions is calculated to be above the minimum required voltage as indicated in Table 2.3.3-3.

6.9 kV Motor Load Requirements

The condensate pump motors and reactor coolant pump motors are affected by station operation at SPU conditions. The condensate pump and steam generator feedwater pump motor load requirements remain within their nameplate ratings and are within the brake horsepower loads in the existing load flow/voltage profile analysis and do not require re-evaluation. Since the SPU brake horsepower requirements do not exceed the existing analyzed brake horsepower requirements, the feeder breakers and cables are bounded by the existing analysis. The condensate and feedwater system is addressed in Section 2.5.5.4, which evaluates the capability of the system to supply adequate feedwater.

The evaluation of the reactor coolant pump motors for operation during hot-loop and cold-loop at SPU conditions is provided in Section 2.2.2.6. The ac onsite power system evaluation determined that the reactor coolant pump motor load requirements exceed the 7000 hp rating for hot-loop and 8750 hp rating for cold-loop worst-case conditions. The evaluation also determined that this is acceptable based on the motor temperature rise not exceeding NEMA MG-1, Section III, Part 20.8 requirements (Class B for hot loop and Class F for cold loop conditions) and the thrust bearing load under both hot and cold loop conditions will be within the thrust bearing design rating.

The calculated full load current for the reactor coolant pump motors during maximum full load at SPU conditions is less than the feeder circuit breaker design rating, the derated cable ampacities for associated motor feeders and electrical penetration conductor ratings. Therefore, the SPU loading requirements for motor feeder breakers and feeder cables are within the equipment design ratings as indicated in Table 2.3.3-4. The design life of the feeder cables is not impacted at SPU.

The increase in design brake horsepower for the reactor coolant pumps will increase the design motor full load current. However, existing motor protective relay settings for both hot and cold loop operation are acceptable for operating currents observed during plant startup and operation.

The electrical penetration protection is provided by the same reactor coolant pump motor protective relay settings for both hot and cold loop operation. These relay settings ensure that the design limits for penetration protection are not exceeded. Separate relays and settings are used for primary and backup protection and for cold and hot loop conditions.

4.16 kV System

The 4.16 kV system is discussed in FSAR Sections 8.3.1.1.1 and 8.3.1.1.2. The evaluation of the 4.16 kV system at SPU conditions confirms the following:

Switchgear Buses and Circuit Breakers, and Non-segregated Phase Bus Duct.

- The SPU load increases are limited to the 6.9 kV reactor coolant pump motors which are isolated from the 4.16 kV buses by being powered from separate normal station service transformers. The SPU load changes for the 4.16 kV motors are the heater drain pump motors and moisture separator drain pump motors. These loads are within the brake horsepower loads provided in the existing load flow/voltage profile analysis. Therefore, the switchgear buses, incoming circuit breakers and non-segregated phase bus ducts are not adversely affected at SPU.
- Since the SPU load changes for the 4.16 kV loads are within the brake horsepower loads provided in the existing load flow/voltage profile analysis, the motor feeder breakers are not adversely affected at SPU.
- There are no changes or modifications to the 4.16 kV system that would increase the short circuit current at SPU conditions. Therefore, the SPU fault duty requirements of the 4.16 kV switchgear buses and breakers would not change from the requirements of the existing analysis.

Power through the MPS3 to MPS2 cross-tie is provided through the 4.16 kV buses to satisfy MPS2 GDC-17 alternate offsite source requirements for minimum post-accident loads. Since the MPS3 4.16 kV system load changes are bounded by those in the existing analysis, the MPS3 to MPS2 cross-tie remains unaffected by SPU.

System Voltage Level

SPU load increases are limited to the 6.9 kV system, which is isolated from the 4.16 kV system. The 4.16 kV system SPU load changes are within the brake horsepower loads provided in the existing load flow/voltage profile analysis. Therefore the existing 4.16 kV system voltages and consequently the existing degraded and loss of voltage relay settings, are not affected by SPU.

4.16 kV Motor Load Requirements

The 4.16 kV system SPU load changes, which include the heater drain pump motors and moisture separator drain pump motors, remain within the brake horsepower load values provided in the existing analysis. Therefore, the motor feeder cables and motor protection are unaffected by SPU and there is no adverse impact on the design life of the motors and feeder cables.

480 V System

The 480 V system is discussed in FSAR Sections 8.3.1.1.1 and 8.3.1.1.2. Evaluation of the 480 V system at SPU conditions confirms the following:

Unit substation transformers, load center bus and circuit breaker ratings, and motor control center ratings.

- There are no SPU load changes that affect the 480 V system. Therefore, the existing load flow/voltage profile analysis is unaffected. The unit substation transformers, 480 V load center bus and associated incoming circuit breaker, and the motor control center load ratings are acceptable as demonstrated in the existing design analysis.
- Since there are no SPU load changes for the 480 V system, the motor feeder breakers remain acceptable as demonstrated in the existing analysis.
- There are no changes or modifications to the 480 V system that would increase the short circuit current at SPU conditions. Therefore, the SPU fault duty requirements of the 480V switchgear buses and breakers are unaffected and remain acceptable as demonstrated in the existing design analysis.

System Voltage Level

Since there are no load changes on the 480 V buses, the 480 V system voltage remains acceptable as demonstrated in the existing voltage profile analysis.

480 V Motor Load Requirements

There are no load changes to 480 V motors under SPU. Therefore the 480 V motor ratings remain acceptable as evaluated in the existing load flow/voltage profile analysis.

Since the 480 V motors are not affected by SPU, the motor feeder breakers, cable sizes and associated electrical penetrations (as applicable) are not affected at SPU conditions and remain acceptable as demonstrated by the existing design analysis and there is no impact on the design life of the motors and cables.

120 V ac System

The 120 V ac system is discussed in FSAR Sections 8.3.1.1.1 and 8.3.1.1.2. There are no load changes to the 120 V ac system under SPU. The evaluation determined that no new components requiring power from the vital and non-vital buses or 120 V ac miscellaneous buses are required to support SPU. Consequently, operation at SPU conditions does not result in load changes or equipment changes to the 120 V ac vital bus and non-vital bus distribution systems or 120 V ac miscellaneous buses. The 120 V ac system remains bounded by the existing analysis.

Emergency Diesel Generators

The emergency diesel generators are discussed in FSAR Section 8.3.1.1.3. Review of the loads for operation at SPU conditions indicates that there are no load additions or modifications required to the existing 5335 kW (2000 hour) emergency diesel generators. Therefore, there is no impact to the existing emergency diesel generator loading analysis and their acceptability for SPU operation. No emergency diesel generator modifications are required to support SPU operation.

Main Generator

The main generator is discussed in FSAR Sections 8.1, 8.1.4, 8.3.1.1.1, 8.3.1.1.2 and 8.3.1.1.4. The main generator rating is 1354.7 MVA @ 0.925 power factor or 1253.1 MW. The evaluation determined that the existing generator rating is adequate to support a maximum output of 1297.6 MW @ 0.958 power factor lagging.

GE Energy Services performed a detailed study of the steam turbine generator capability and it was determined that the main generator has the capability to support the output submitted to ISO-NE of 1296 MW by increasing the operating power factor from 0.925 to 0.957 lagging without modifications. There is no leading reactive power requirement for the main generator. Refer to Table 2.3.3-5 for generator operation at lagging power factor.

Isolated Phase Bus Duct

The isolated phase bus duct is discussed in FSAR Sections 8.1.4, 8.3.1.1.1 and 8.3.1.1.2. The isolated phase bus duct main bus has been evaluated under worst-case SPU loading conditions. The main bus of the isolated phase bus duct forced cooled continuous current design rating is 34.4 kA which envelopes the anticipated worst-case SPU loading of 34.3 kA as indicated in Table 2.3.3-6. The isolated phase bus duct tap connected to normal station service transformer (NSST) B will experience an increase in load current under SPU conditions due to increased reactor coolant pump motor load. The resulting load current of 1.1 kA is well within the isolated phase bus tap bus continuous current design rating of 4.0 kA as indicated in Table 2.3.3-7. The isolated phase bus duct tap to NSST A is not affected by SPU conditions.

The isolated phase bus duct tap to main transformers A and B has been evaluated under worst-case loading conditions. The anticipated worst-case load on the isolated phase bus duct tap to each of the main transformers is 17.1 kA and 17.2 kA, respectively, which is within the isolated phase bus duct tap continuous current design rating of 18.8 kA as indicated in Table 2.3.3-8.

The equipment short circuit duty rating is not impacted at SPU conditions because unit operation does not require any equipment changes, replacements and/or new installations that could result in increased equipment fault current. Therefore, the short circuit current levels calculated prior to SPU are the same as the short circuit current levels after implementation of SPU.

Generator Circuit Breaker

The generator breaker is discussed in FSAR Section 8.3.1.1.4. The generator breaker has been evaluated under worst-case SPU loading conditions, which are the same conditions as used for evaluation of the isolated phase bus duct main bus. The continuous current rating of the generator circuit breaker of 37.5 kA envelopes the anticipated worst-case loading of 34.3 kA at SPU conditions as indicated in Table 2.3.3-9. The short circuit duty of the generator breaker is not impacted by SPU conditions since unit operation does not require any equipment changes, replacements and/or new installations that could result in increased equipment fault current.

GDC-17 Requirements

The load flow/voltage profile analysis and short circuit current analysis indicate that the ac onsite power system equipment voltages and fault duties are not adversely affected by SPU conditions. The loading requirements of the evaluated equipment are bounded by equipment design ratings. Therefore, the ac onsite power system will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-17, and perform its intended functions during anticipated operational occurrences and accident conditions, following implementation of the proposed SPU.

2.3.3.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the ac onsite power system. DNC concludes that the evaluation has adequately accounted for the proposed SPU effects on the systems functional design. DNC further concludes that the system will continue to supply power to safety related equipment. Based on this, the ac onsite power system will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-17 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the ac onsite power system.

Table 2.3.3-1
NSST-B Maximum Input Loading on the H Winding

Primary Winding	H- Winding			Design Rating	Reference
	MW	MVAR	MVA	MVA	
Existing	36.98	20.49	42.28	30/40/50 OA/FA/FA @65°C	Note 1
SPU+Existing	38.69	20.18	43.64		Note 2
Increment	1.71	-0.31	1.36		Note 3
Total Input Load	38.69	20.18	43.64	50@65°C	

Notes:
1. Existing MW, MVAR and MVA loading is derived from load flow analysis. These values present the worst case present loading on the transformer.
2. SPU+Existing loading are derived from load flow analysis. These values represent the total loading on the transformer after SPU.
3. Increment loading is the difference between the Existing loading (Note 1) and SPU + Existing loading (Note 2). These values represent the additional loading on NSST B as a result of SPU.

Table 2.3.3-2
6.9 kV Switchgear Bus Load

Switchgear	**Worst-case Existing**	**Worst-case SPU**	**Switchgear/ Non-Segregated Bus/Bkr**
Buses	Current	Current	Rating
	Load Amps	Load Amps	Amps
	(Note 1)	(Note 1)	(Note 2)
Bus 35A	806.9	836.1	2000
Bus 35B	809.8	839.1	2000
Bus 35C	1349.3	1377.4	2000
Bus 35D	819.9	848.9	2000

Notes:

1. Worst case existing and worst-case SPU load currents are from load flow/voltage profile analysis.
2. Design rating of switchgear bus, incoming breakers and rectangular non-segregated bus is derived from equipment specifications.

Table 2.3.3-3
Worst Case Minimum Steady-State Motor Voltages, Existing and SPU Conditions for 6.9 kV Switchgear Bus Motors

Motor	Bus	Motor Rated Voltage (Note 1)	Voltage (V) Minimum Steady State		
			Existing Calc. Mtr. Term. Volts (Note 1)	SPU Calc. Mtr. Term. Volts (Note 1)	Min.Mtr.Term Volt Req. (Note 1)
Reactor Coolant Pump 3RCS-P1A	35A	6600	6677	6676	5940
Reactor Coolant Pump 3RCS-P1B	35B	6600	6653	6653	5940
Reactor Coolant Pump 3RCS-P1C	35C	6600	6576	6579	5940
Reactor Coolant Pump 3RCS-P1D	35D	6600	6573	6577	5940
Condensate Pump 3CNM-P1A	35A	6600	6672	6672	5940
Condensate Pump 3CNM-P1B	35B	6600	6647	6646	5940
Condensate Pump 3CNM-P1C	35D	6600	6567	6570	5940

Note 1:
The voltage values are obtained from the load flow/voltage profile analyses.

Table 2.3.3-4
RCP Motor Load, Feeder Cable, Electrical Penetration and Breaker Rating Comparison at SPU Conditions

Motor	**Motor Load, Amps (Note 1)**	**Cable Rating, Amps (Note 2)**	**Electrical Penetration Rating, Amps (Note 2)**	**Breaker Rating, Amps (Note 2)**
Reactor Coolant PP RCP 1A	535.2	614	641	1200
Reactor Coolant PP RCP 1B	537.1	614	641	1200
Reactor Coolant PP RCP 1C	543.1	614	641	1200
Reactor Coolant PP RCP 1D	543.3	614	641	1200

Note:
1. Motor load current is from the load flow/voltage profile analysis, hot loop conditions.
2. Equipment ratings are derived from design calculations and/or specifications.

Table 2.3.3-5
Generator Operation at Lagging Power Factor

Generator Output					Notes
MW	**MVAR**	**MVA**	**Volts, kV**	**PF(%)**	
1297.6	389.2	1354.7	24	95.8	1
1295.8	395	1354.7	24	95.7	2

Notes:
1. Generator output operating point derived from the bounding SPU heat balance case and generator capability curve. There is no leading reactive power capability requirement.
2. Proposed generator output operating point submitted to ISO New England for evaluation and approval is 1296 MW and 395 MVAR.

Table 2.3.3-6
IPBD Main Bus Loading Unit Operating at Lagging Power Factor (Exporting VARs)

Generator Output (SPU)				IPBD Main Bus Load (kA) (Note 1)	IPBD Main Bus Rating (kA)
MW	**MVAR**	**MVA**	**Voltage (p.u.)**		
1297.6	389.2	1354.7	0.95	34.3	34.4

Note:

1. IPBD Main Bus Load Current (kA) $= \dfrac{MVA(gen)}{24KV(0.95)\times\sqrt{3}}$

Table 2.3.3-7 IPBD Tap Bus to NSST Loading

IPBD Tap Bus to	Load (kA)	Rating (kA)	Note
NSST B	1.1	4.0	1

Note:

1. IPBD Tap Bus to NSST Load Current $= \dfrac{MVA(nsst)}{24KV(0.95)\times\sqrt{3}}$

Table 2.3.3-8
IPBD Tap Bus to Main Transformers Loading
(No Station Auxiliary Loads Supplied From NSSTs)

Generator Output (Lagging Power Factor)				Tap Bus to MT A Load (kA) (Note 1)	Tap Bus to MT B Load (kA) (Note 1)	Tap Bus To MT's Rating (kA)
MW	**MVAR**	**MVA**	**Voltage (p.u.)**			
1297.6	389.2	1354.7	0.9462	17.1	17.2	18.8

Note:
1. The main transformer tap bus loads are obtained from load flow analysis and adjusted by 0.996 (0.9462 p.u./0.95 p.u.) to represent load current when the generator is at SPU output and minimum design voltage of 0.95 p.u. of generator rated voltage.

Table 2.3.3-9
Generator Breaker Loading

Generator Output (SPU) (kA)	Generator Breaker Rating (kA)	Note
34.3	37.5	1

Note:

1. Generator Output (kA) $= \dfrac{MVA(gen)}{24KV(0.95)\times\sqrt{3}}$

2.3.4 DC Onsite Power System

2.3.4.1 Regulatory Evaluation

The dc onsite power system includes the dc power sources and their distribution and auxiliary supporting systems that supply motive or control power to safety-related equipment. DNC review covered the information, analyses, and referenced documents for the dc onsite power system.

The acceptance criteria for this review are based on

- GDC-17, insofar as it requires that the system have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions.

Specific review criteria are contained in SRP Sections 8.1 and 8.3.2, and guidance is provided in Matrix 3 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Sections 8.1 and 8.3.2, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in FSAR Section 3.1.2.

- GDC-17 is described in the FSAR Section 3.1.2.17, General Design Criteria 17 - Electric Power Systems.

  Two connections to the offsite power system are provided. The preferred offsite connection is a backfeed through the main and normal station service transformers with the generator breaker open. The alternate offsite connection is through the reserve station service transformers. Each offsite source has 100 percent capacity for all emergency and normal loads during all phases of operation, plus the capacity to supply Millstone Unit 2 GDC-17 requirements through the NSST or RSST as an alternate offsite source for minimum post-accident loads.

  Two onsite power systems are provided, each having an emergency diesel generator. Each diesel generator has 100 percent capacity for the emergency loads in the event of the postulated accidents or required for reactor cooldown.

  The design of the electrical system (Chapter 8) conforms to Criterion 17.

Additional details that define the licensing basis are described in FSAR Section 8.3.2, DC Power Systems. The Class 1E dc power system has redundancy, capacity, capability, and reliability to supply power to all safety-related loads, even in the event of a single failure, by maintaining electrical independence between redundant trains and channels in accordance with GDC-17, -22, -33, -34, -35, -38, -41 and -44. Power is available to these loads for at least 2 hours in the event of loss of all ac power. After 2 hours it is assumed the ac power is either restored or that the emergency generators are available to energize the battery chargers.

As addressed in NUREG-1031, MPS3 Safety Evaluation Report, August 2, 1984, Section 8.3.2, Onsite DC System's Compliance with GDC-17, MPS3 has met (except as noted) the requirements of GDC-17 with respect to the dc system's: (1) capacity and capability to permit functioning of structures, systems, and components important to safety; (2) independence, redundancy, and testability to perform their safety function assuming a single failure; and (3) provisions to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit or the loss of power from the transmission network.

Additionally, the NRC staff identified actions to be taken by the licensee relative to Generic Issues 48 and 49, GL 91-11, "Resolution of Generic Issues 48, 'LCOs for Class 1E Vital Instrument Buses', and 49, 'Interlocks and LCOs for Class 1E Tie Breakers' Pursuant to 10 CFR 50.54 (f)", dated July 18, 1991. The three issues as described in GL 91-11 were reviewed and verified to meet Generic Issues 48 and 49 at MPS3. In a letter from NRC (J.F. Stolz) to NNECo (J.F. Opeka), dated March 6, 1992, the NRC stated that it had reviewed NNECo's response to GL 91-11 and found that it met the reporting requirements set forth in GL 91-11.

In addition to the evaluations described above, the dc onsite power system was evaluated for the continued acceptability for the purpose of plant license renewal. The results of that review are found in NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Units 2 and 3, dated August 1, 2005. The SER documents system and system component materials of construction, operating history, and programs used to manage aging effects. The dc onsite power system was determined to be within the scope of the license renewal, and components subject to age management review are evaluated on a plant wide basis as commodities. The generic commodity groups are described in SER Section 2.5.

2.3.4.2 Technical Evaluation

2.3.4.2.1 Introduction

The 125 V dc onsite power system is described in the FSAR Section 8.3.2. The 125 V dc power system consists of six separate systems: two normal dc systems supplying nonsafety related loads, and four Class 1E dc systems supplying safety-related loads.

The Class 1E 125 V dc power system is divided into four separate channels: two are devoted exclusively to supplying the associated regulated 120 V ac vital bus power supply; the other two channels, in addition to supplying the associated regulated 120 V ac vital bus loads, also supply other safety-related dc loads. The Class 1E 125 V dc power system equipment for each channel consists of one operating battery charger, one spare battery charger shared by two channels of the same train, one 125 V dc battery, and one distribution switchboard. On each of the two channels that also supply other safety-related dc loads, additional distribution panels are included.

The function of the dc power system is to provide a source of power within acceptable design limits for controls, emergency lighting, and the inverters for critical 60-cycle instrument power if all other sources of power are interrupted.

The 125 V dc power system provides the battery capacity to cope with Station Blackout and Fire Protection Program/BTP 9.5-1 Safe Shutdown conditions.

2.3.4.2.2 Description of Analysis and Evaluations

The 125 V dc power system and its components were evaluated to ensure they are capable of performing their intended function at SPU conditions. The evaluation is based both on the system's required design functions and attributes and upon a comparison between the existing dc equipment ratings and the anticipated operating requirements at SPU conditions. Station Blackout and Fire Protection Program/BTP 9.5-1 Safe Shutdown Evaluations are included in this evaluation.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above in Section 2.3.4.1, the dc onsite power system is within the scope of license renewal. However, the changes associated with operating the dc system at SPU conditions do not add any new or previously unevaluated materials to the system, nor do they exceed the operating or environmental parameters previously evaluated for equipment included within the scope of the rule. Thus, no new aging effects requiring management are identified.

2.3.4.2.3 Results

The safety-related and non safety-related portions of the 125 V dc systems were evaluated to determine potential impacts due to SPU.

The BOP systems, including the turbine generator auxiliaries, were reviewed, and it was determined that no new dc loads were added, nor were any dc load increases identified for the existing loads. The NSSS was reviewed and it was determined that no new dc loads were added, nor were any dc load increases identified for the existing loads. In addition, Station Blackout and Fire Protection Program/BTP 9.5-1 Safe Shutdown evaluations did not result in any 125 V dc load changes as discussed in Section 2.3.5 and 2.5.1.4.

Therefore, the battery duty cycle, voltages at equipment, and available fault currents are unaffected by SPU; they remain within the existing design bases as documented in the existing calculations.

The 125 V dc power system continues to have the capacity and capability to perform its function. because there are no new loads added. Therefore, separate and independent station battery systems are maintained to supply power to all safety loads in accordance with the MPS3 current licensing basis with respect to the requirements of GDC-17.

2.3.4.3 Conclusion

The evaluation concluded that there are no new loads added or any load changes to the onsite dc power system. The dc onsite power system will continue to function as designed and will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-17 following implementation of the proposed SPU. Adequate physical and electrical separation exists, and the dc power system has the capacity and capability to supply power to all safety loads and other required equipment at SPU conditions.

2.3.5 Station Blackout

2.3.5.1 Regulatory Evaluation

Station blackout (SBO) refers to a complete loss of ac electric power to the essential and nonessential switchgear buses in a nuclear power plant. Station blackout involves the loss of offsite power concurrent with a turbine trip and failure of the onsite emergency ac power system. Station blackout does not include the loss of available ac power to buses fed by station batteries through inverters or the loss of power from “alternate ac sources.” The review focused on the impact of the proposed SPU on the plant’s ability to cope with and recover from an SBO event for the period of time established in the licensing basis.

The acceptance criteria for station blackout are based on:

- 10 CFR 50.63, “Loss of All Alternating Current Power,” which requires that each light-water cooled nuclear power plant licensed to operate must be able to withstand a station blackout for a specified duration and recover from the station blackout.

Specific review criteria are contained in the SRP Sections 8.1 and 8.2, and other guidance is provided in Matrix 3 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 8.1, Rev. 2, and Section 8.2, Rev. 3.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2. The FSAR has been updated to address compliance with 10 CFR 50.63, which was issued after the initial licensing of MPS3.

Specifically, the adequacy of MPS3 Station design relative to conformance to:

- 10 CFR 50.63 is described in FSAR Sections 8.1.4, Onsite Electric System; 8.1.8, Station Blackout Analysis Summary; 8.3.1.1.5, Alternate AC Power Source Regulatory Requirements; 8.3.1.1.6, Alternate AC System Description; 8.3.1.1.7, Alternate AC Design Criteria and Compliance; and Table 1.8-1, NRC Regulatory Guides.

  As addressed in FSAR Section 8.3.1.1.5, the Nuclear Regulatory Commission (NRC) amended its regulations in 10 CFR 50. A new section, 50.63, was added which requires that each light water cooled nuclear power plant be able to withstand and recover from a Station Blackout of a specified duration. The NRC has issued RG 1.155, Station Blackout, which describes a means acceptable to the NRC staff for meeting the requirements of 10 CFR 50.63. RG 1.155 references Nuclear Management and Resource Council (NUMARC) 87-00, “Guidelines and Technical Bases for NUMARC Initiatives for Addressing Station Blackout at Light Water Reactors” which provides guidance that is in large part identical to the RG 1.155 guidance and is acceptable to the NRC staff for meeting these requirements.

As addressed in FSAR Table 1.8-1, DNC complies with RG 1.155.

Station Blackout Duration

As addressed in FSAR Section 8.1.8, the minimum acceptable station blackout coping duration for Unit 3 was calculated to be 8 hours. Several factors are used to determine the coping duration. These factors include offsite power design characteristics, emergency ac configuration, emergency diesel generator (EDG) target reliability, estimated frequency of loss of offsite power due to severe weather, and estimated frequency of loss of offsite power due to extremely severe weather.

Alternate AC Power Source

As addressed in FSAR Section 8.1.4, the AAC Source provides power to that equipment required to remove residual heat from the Reactor Coolant System in the event of a Station Blackout in Unit 3 or Unit 2 whereby both the offsite power system and the respective standby power system is not available. The AAC Source consists of a SBO diesel generator and its support equipment (battery, inverter, computer, ventilation, etc.) adequately sized to power equipment required to maintain the plant in a safe condition in the event both the offsite power system and standby power system are unavailable for up to 8 hours.

As addressed in FSAR Sections 8.3.1.1.5, 8.3.1.1.6, and 8.3.1.1.7, in order to meet coping duration requirements of RG 1.155, an Alternate ac power source was installed. This AAC power source meets the criteria specified in Appendix B to NUMARC 87-00 and is available within 1 hour after the onset of an SBO event. The AAC Source is a 2,260 kW, 3-phase, 0.8 power factor, 60 Hz, 4160 VAC Diesel Generator which can provide power to either of the MP3 4.16 kV emergency buses via the normal buses. The AAC Source provides a backup to the Emergency Diesel Generators and satisfies the requirements of 10 CFR 50.63, RG 1.155, and NUMARC 87-00 for coping with an SBO event. The AAC system and all its components were designed and procured as a non-Class 1E system.

As addressed in FSAR Section 8.3.1.1.6, the AAC power source can also provide power to Millstone Unit 2 in the event of an SBO event at that unit. A station blackout is assumed to occur in one unit only (MPS2 or MPS3).

As addressed in FSAR Section 8.3.1.1.7, the AAC power system is started, brought to operating conditions, and operated at its continuous power rating every three months. Every 24 months, a simulated black start and capacity test at the 168 hour rating is performed.

Ability to Cope with a Station Blackout

As addressed in FSAR Section 8.1.8,10 CFR 50.63 required each plant to assess the capability of their plant to maintain adequate core cooling and appropriate containment integrity during a station blackout of the minimum calculated duration, and to have procedures to cope with such an event. The assessment for MPS3 required the unit to cope with an 8 hour station blackout event. RG 1.155 specified the following topics for inclusion in the assessment.

- Condensate Inventory

  An evaluation showed that the minimum permissible Technical Specification level for the demineralized water storage tank provides sufficient volume to cope with a station blackout event of 8 hours.

- Class 1E Battery Capacity

  There is sufficient battery capacity for one hour, at which time the SBO diesel generator (AAC power source) will be aligned to one of the two emergency buses. An analysis determined that the battery on the bus not powered by the SBO diesel generator has sufficient capacity to start the associated train emergency diesel generator, flash its field and close its output breaker, or to close the associated train reserve station service transformer breaker at the end of the 8 hour station blackout event.

- Compressed Air

  No compressed air is required to cope with the station blackout event.

- Loss of Ventilation

  The effects of post-SBO air temperatures were analyzed for areas in the plant containing SBO equipment. These areas included the turbine driven auxiliary feedwater pump room, main steam valve building, charging pump cubicle, the main control room, the instrument rack room, and both switchgear rooms (east and west). The results of these analyses were factored into procedure modifications. No plant modifications were required due to the analysis results.

- Containment Isolation

  Containment isolation valves were reviewed to verify which valves must be capable of being closed or cycled during an SBO event, independent of the preferred and blacked out unit's Class 1E power supply. The review showed no modifications or procedure changes were required to ensure that appropriate containment integrity will be maintained.

- Reactor Coolant Inventory

  An analysis was performed and determined that there is sufficient RCS inventory during the first hour of the SBO event. Subsequent to this, the SBO diesel is aligned to one of the emergency buses. One charging pump is then used to establish RCS makeup for the remainder of the 8 hour SBO event.

- Procedures

  Appropriate procedures have been reviewed and modified as necessary. These procedure modifications meet the guidelines of NUMARC 87-00.

- Modifications

  Evaluations determined that an alternate source of ac power was required in order to cope with an 8 hour station blackout event. An independent, alternate ac diesel generator was installed.

The NRC SBO Safety Evaluation (Reference: Letter from D. Jaffe [NRC] to E. J. Mroczka [NNECO] dated January 30, 1992) and supplemental SBO Safety Evaluation (Reference: Letter from V. L. Rooney (NRC) to J. F. Opeka [NNECO], dated September 23, 1992) concluded that the MPS3 design and proposed method of dealing with an SBO were in conformance with the SBO rule and that MPS3's responses to the staff's recommendations were acceptable.

In addition to the evaluations described above, plant systems/equipment required to cope with an SBO event at MPS3 were evaluated for continued acceptability for the purpose of plant license renewal. The results of that review are documented in NUREG-1838, "Safety Evaluation Report (SER) Related to the License Renewal of the Millstone Power Station, Units 2 and 3," dated August 1, 2005. The station blackout diesel generator system, which includes the SBO diesel generator and supporting subsystems, is evaluated in Sections 2.3B.3.44 and 3.3B.2.3.41 of the License Renewal SER. Other systems/equipment credited with coping with an SBO event are addressed in the respective system evaluations contained in the License Renewal SER.

2.3.5.2 Technical Evaluation

2.3.5.2.1 Introduction

The postulated MPS3 SBO event assumes that prior to the SBO the reactor has been operating at 100 percent rated thermal power and has been at this power level for at least 100 days. The initiating SBO event is assumed to be a loss of all off-site power at the MPS3 site resulting from a switchyard-related event or an external event. The external event may be a grid disturbance or a weather event that affects the off-site power system either throughout the grid or at the plant. The preferred on-site emergency ac power sources are assumed to be unavailable.

DNC has prepared a specification that provides the analysis methodologies, baseline assumptions, analysis results, and related information demonstrating MPS3 conformance with the SBO Rule for current plant conditions.

The decay heat used for the analyses of condensate required to remove decay heat and the AFW flow rate required to remove decay heat for an SBO event at SPU conditions is based on ANSI/ANS-5.1-1979, "Decay Heat Power in Light Water Reactors." The decay heat fraction/integrated power (full-power-seconds) data used in the analyses at the SPU power level were determined based upon essentially an infinite operating period (10,000 days).

2.3.5.2.2 Description of Analyses and Evaluations

The following topics are evaluated for impact of the SPU:

1. SBO coping duration

2. Plant equipment required to cope with an SBO event

3. Alternate ac power source

4. SBO event coping assessment, which addresses condensate inventory for decay heat removal and plant cooldown, Class 1E battery capacity, compressed air, effects of loss of ventilation, containment isolation, and reactor coolant inventory

5. AFW system flow rate requirements

6. Plant procedures

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed in Section 2.3.5.1, plant systems/equipment required to cope with an SBO event at MPS3 are within the scope of plant license renewal, and that systems/equipment evaluated include the SBO diesel generator system.

As addressed in the NRC's evaluation of the SBO diesel generator and supporting subsystems, the NRC found that MPS3 had acceptable programs for managing the aging effects applicable to this equipment (e.g., cracking of stainless steel components, loss of material due to pitting and corrosion). The SPU does not add any new materials to this equipment, does not affect the existing materials, and does not affect the environments to which these materials are exposed. Therefore, the SPU does not affect the evaluations/conclusions in the License Renewal SER regarding the SBO diesel generator system, and no new aging effects requiring management are identified.

Other systems/equipment credited with coping with an SBO event are addressed in the respective system evaluations contained in the License Renewal SER.

2.3.5.2.3 Results

1. Coping Duration

The minimum acceptable SBO coping duration for MPS3 utilizing the guidance of RG 1.155 and the methodology of NUMARC 87-00 has been determined to be 8 hours. The current SBO coping duration category is based on the following characteristics/criteria:

- Site susceptibility to grid-related loss of off-site power events
- Extremely severe weather group
- Severe weather group
- Off-site power system independence group
- Emergency ac power sources configuration
- Allowed (minimum) EDG target reliability

An evaluation was performed to determine the impact of the SPU on the current SBO coping duration category of 8 hours. This evaluation shows that the site characteristics are unchanged and the EDG minimum reliability criteria are maintained at SPU conditions. Therefore, the SPU does not affect the MPS3 coping duration of 8 hours.

2. Plant Equipment Required to Cope with an SBO Event

The equipment required to cope with an SBO event performs the following functions:

- Decay heat removal
- Reactor coolant inventory
- Plant stability
- Containment integrity
- Alternate ac power
- Monitoring and control of critical system parameters
- ac power
- 125 V dc power
- Temperature environment

Systems that contain components required to perform the above-listed functions during an SBO event, and the corresponding LR sections which evaluate impact of the SPU on these systems, include the following:

- Auxiliary Feedwater System – Section 2.5.4.5
- Main Steam System – Section 2.5.5.1
- Chemical & Volume Control System – Section 2.1.11
- Service Water System – Section 2.5.4.2
- AC Onsite Power System – Section 2.3.3
- DC Onsite Power System – Section 2.3.4
- Ventilation Systems – Section 2.7.3.1 (Control Room Area), Section 2.7.5 (Auxiliary and Radwaste Area and Turbine Area), and Section 2.7.6 (Engineered Safety Feature)

Based on the evaluations of systems required to perform the above-listed functions during an SBO event, there are no changes in the components required to cope with an SBO event at SPU conditions that would affect the capability of these components to perform their required functions during an SBO event.

3. Alternate AC Power Source

The AAC power source includes the SBO diesel generator and its support subsystems (e.g., starting air, cooling water, lubrication, and fuel oil systems).

As addressed in Section 2.3.5.1, the SBO diesel generator can provide power to either of the MPS3 4160V ac emergency buses via the 4160 V ac normal buses. The 4160V ac normal bus is stripped of all major loads prior to tying the SBO diesel generator to the bus. Non-safety-related battery 5 provides control power for load stripping of the normal bus and for closing the SBO diesel generator tie breaker. As addressed in Section 2.3.4, the plant safety-related and non-safety related dc systems are not affected by the SPU. Therefore, the SPU does not affect battery 5, and does not affect the capability of stripping the normal bus and closing the SBO diesel generator tie breaker for an SBO event.

The impact of the SPU on the current analyses associated with the SBO diesel generator follows:

a. An analysis shows that the SBO diesel generator steady state and peak kW loading for an SBO event is acceptable at current plant conditions. As discussed in Item 2 above, there are no changes in the existing components required to cope with an SBO event at SPU conditions that would affect the capability of these components to perform their required functions during an SBO event. Therefore, there are no load increases at SPU conditions that would affect the conclusions of the current SBO diesel generator loading analysis.

b. The current analysis of SBO diesel generator run time determines a run time of 73.7 hours at the 168 hour rating of 2574 kW. This run time greatly exceeds the SBO coping duration of 8 hours. As discussed above, for an SBO event at SPU conditions, there are no load increases that would affect the conclusions of the current SBO diesel generator loading analysis. Therefore, the SPU does not affect the current analysis of SBO diesel generator run time.

As addressed in Section 2.3.5.1, the AAC power system is started, brought to operating conditions, and operated at its continuous power rating every three months. Every 24 months, a simulated black start and capacity test at the 168 hour rating is performed. These 3-month and 24-month tests of the AAC power system are not affected by the SPU.

Based on the above, the SPU does not affect the SBO diesel generator or its supporting subsystems and components. The SPU does not affect the capability of the SBO diesel generator auxiliary equipment to start-up the SBO diesel generator within one hour of an SBO event.

4. SBO Event Coping Assessment

   a. Condensate Inventory for Decay Heat Removal and Plant Cooldown

      Using the current analysis methodology, an analysis has determined that the condensate (DWST) inventory required for decay heat removal and plant cooldown for an SBO event at SPU conditions is 172,858 gallons. The Technical Specification 3.7.1.3, Demineralized Water Storage Tank, requires a minimum of 334,000 gallons of water in the DWST. Therefore, the DWST Technical Specification minimum volume exceeds the condensate (DWST) inventory required for decay heat removal and plant cooldown for an 8 hour SBO event at SPU conditions.

   b. Class 1E Battery Capacity

      During an SBO event, the AAC power source is available to power the battery charger associated with either Class 1E station battery 1 (train A) or battery 2 (train B) within one hour. As discussed in Item 2 above, there are no changes in the existing components required to cope with an SBO event at SPU conditions that would affect the capability of these components to perform their required functions during an SBO event. There are no 125 V dc load additions or changes required to cope with an SBO event at SPU conditions. Accordingly, batteries 1 and 2 are not affected by the SPU and continue to have sufficient capacity to meet SBO loads for the first hour of the SBO event.

The current analysis that demonstrates that the battery of the train that is not connected to the AAC power source has sufficient capacity to restore either its associated emergency diesel generator or off-site power, whichever becomes available at the end of the SBO 8 hour coping period, is not affected by the SPU.

c. Compressed Air

The purpose of this assessment is to ensure that any air-operated valves that would be required for decay heat removal have sufficient compressed air or can be manually operated under SBO conditions. MPS3 air-operated valves are designed to fail safe on loss of power (the turbine-driven auxiliary feedwater pump steam supply air-operated valves fail open on loss of power). No air-operated valves are relied on to cope with an SBO event at current plant conditions. No air-operated valves are required for coping with an SBO event at SPU plant conditions.

d. Effects of Loss of Ventilation

Regarding the effects of loss of ventilation inside the Containment, NUMARC 87-00 assumes Containment temperatures resulting from loss of ventilation are enveloped by LOCA and HELB environmental profiles. Reasonable assurance of operability of SBO equipment inside Containment is provided since safe shutdown equipment is qualified for the accident environments under the MPS3 EEQ program. Impact of the SPU on the accident environment inside Containment is addressed in Section 2.3.1.

The following areas outside Containment are identified as dominant areas of concern (i.e., areas having a post-SBO 8 hour steady state ambient air temperature greater than 120°F): Turbine Driven Auxiliary Feedwater Pump Room, Main Steam Valve Building, and the Charging Pump Cubicle. Discussion of the impact of the SPU on the current analyses/evaluations of the areas reviewed for loss of ventilation follows:

- Turbine Driven Auxiliary Feedwater Pump Room

  The current analysis determines that the maximum temperature in the Turbine Driven Auxiliary Feedwater Pump Room for an 8 hour SBO event is 150°F. This maximum temperature occurs during the first hour of the event, when no ventilation is provided to the room. Room ventilation powered by the AAC Source maintains the room temperature below 150°F during the final 7 hours of the SBO event. Operability of SBO equipment in this room at current conditions is not affected, since this equipment is qualified to temperatures which exceed 150°F.

The current analysis established heat generation rates in the Turbine Driven Auxiliary Feedwater Pump Room based on a main steam temperature of 600°F. The 600°F main steam temperature assumed in the Turbine Driven Auxiliary Feedwater Pump Room ventilation analysis remains bounding for the SPU based on the following: For a station blackout event, steam generator secondary side pressure and main steam system operating temperature are determined initially by MSSV operation. RCS decay heat quickly reduces to the point were the lowest MSSV releases sufficient steam. The nominal setpoint for this lowest MSSV is 1200 psia, which corresponds to an approximate 567°F saturation temperature.

Therefore, since the main steam temperature used in the analysis for current plant conditions envelopes the main steam temperature at SPU conditions, the SPU does not affect the results of the current plant analysis for the maximum temperature in the Turbine Driven Auxiliary Feedwater Pump Room.

- Main Steam Valve Building

  The current analysis determines that the maximum temperatures in the Main Steam Valve Building for an 8 hour SBO event are: greater than 120°F without forced ventilation, and less than 120°F with forced ventilation operated when the AAC power source is available one hour after start of the SBO event. Assurance of operability of SBO equipment in this building is provided since safety-related equipment is qualified to withstand a main steam system high energy line break. Precautions which address minimizing personnel exposure to elevated temperatures in the building are included in the “loss of all ac power” EOPs.

  The current analysis established heat generation rates in the Main Steam Valve Building based on a main steam temperature of 600°F and main feedwater temperature of 470°F.

  The 600°F main steam temperature assumed in the Main Steam Valve Building ventilation analysis remains bounding for the SPU based on the following: For a station blackout event, steam generator secondary side pressure and main steam system operating temperature are determined initially by MSSV operation. RCS decay heat quickly reduces to the point were the lowest MSSV releases sufficient steam. The nominal setpoint for this lowest MSSV is 1200 psia, which corresponds to an approximate 567°F saturation temperature.

  As addressed in Section 1.1, Table 1-1, at SPU conditions the main feedwater temperature is 445.3°F.

  Therefore, since the main steam temperature and main feedwater temperature used in the analyses for current plant conditions envelope the main steam temperature and main feedwater temperature at SPU conditions, the SPU does not affect the results of the current plant analysis for maximum temperatures in the Main Steam Valve Building.

- Charging Pump Cubicle

  The current analysis determines that the maximum temperature in the Charging Pump Cubicle for an 8 hour SBO event without forced ventilation is greater than 120°F. The "loss of all ac power – recovery with SBO diesel" EOP contains instructions for supplying ventilation to the charging pump area when the AAC power source is available.

The current analysis established heat generation rates in the Charging Pump Cubicle based on one charging pump operating continuously at motor nameplate horsepower to make up for RCP seal leakage. The current analysis of time to core uncovery due to RCS leakage, including RCP seal leakage, uses a charging flow rate of 100 gpm (refer to Item "f" below). The analysis of time to core uncovery due to RCS leakage, including RCP seal leakage, at SPU conditions also uses a charging flow rate of 100 gpm. An evaluation has been performed to confirm the capability of the charging pump to provide a charging flow rate of 100 gpm.

Therefore, since the charging flow rate for make up of RCP seal leakage remains unchanged for SPU conditions, the assumed charging pump horsepower used in the Charging Pump Cubicle ventilation analysis remains valid for SPU conditions, and the SPU does not affect the results of the current plant analysis for maximum temperature in the Charging Pump Cubicle.

- Control Room

The current analysis determines that the maximum temperatures in the Control Room for an 8 hour SBO event without forced ventilation are: less than 110°F with an initial room temperature of 75°F, and slightly greater than 110°F with an initial room temperature of 95°F. Control Room ventilation is utilized to satisfy the human habitability room temperature limit of 110°F given in NUMARC 87-00. The "loss of all ac power – recovery with SBO diesel" EOP includes instructions for placing the Control Building ventilation system in service after power is supplied from the AAC power source.

As addressed in Section 2.7.3.1, the Control Room heat gain loads for the ventilation system are not impacted by the SPU. Therefore, the SPU does not affect the maximum Control Room temperatures for an 8 hour SBO event as determined in the current analysis.

- Instrument Rack Room

The current analysis determines that the maximum temperature in the Instrument Rack Room for an 8 hour SBO event is less than 99.4°F. Since this room is not identified as a dominant area of concern, no special actions are required to comply with the SBO rule. However, as a prudent operating practice, the MPS3 "loss of all ac power" EOP directs opening of access doors for designated Instrument Rack Room control panels during an SBO event.

As addressed in Section 2.7.3.1, the SPU does not affect the heat loads in the Instrument Rack Room. Therefore, the SPU does not affect the maximum temperature in this room for an 8 hour SBO event as determined in the current analysis, and does not affect the MPS3 commitment to open designated Instrument Rack Room control panel doors.

- East and West Switchgear Rooms

  The current analyses determine that the maximum temperatures in the East and West Switchgear Rooms for an 8 hour SBO event without forced ventilation are 114°F and 95°F, respectively. Reasonable assurance of operability for vital inverters has been provided via vendor documentation. As a conservative approach, the "loss of all ac power – recovery with SBO diesel" EOP includes instructions for operating ventilation for the switchgear rooms after power is supplied from the AAC power source.

  As addressed in Section 2.7.3.1, the SPU does not affect the heat loads in the East and West Switchgear Rooms. Therefore, the SPU does not affect the maximum temperatures in these rooms for an 8 hour SBO event as determined in the current analyses. The SPU does not affect the approach of providing ventilation to these rooms in accordance with "loss of all ac power – recovery with SBO diesel" EOP.

- East and West Rod Control Areas

  As a conservative approach, the "loss of all ac power – recovery with SBO diesel" EOP includes instructions for operating ventilation for the MCC/Rod Control Areas after power is supplied from the AAC Source. The SPU does not affect the approach of providing ventilation to these areas in accordance with this EOP.

- Service Water Pump Cubicles

  These cubicles are not considered dominant areas of concern, since cubicle ventilation is automatically restored when the AAC Source is established during the SBO event. The SPU does not affect this conclusion.

e. Containment Isolation

An evaluation was performed for current plant conditions to confirm that appropriate containment integrity can be provided during an SBO event, where "appropriate containment integrity" is defined as providing the capability for valve position indication and closure of certain containment isolation valves independent of the preferred or Class 1E power supplies.

The initial step consisted of reviewing the listing of containment isolation valves and excluding the following valves from consideration per NUMARC 87-00: (1) valves normally locked closed during operation, (2) valves that fail closed on loss of ac power or air, (3) check valves, (4) valves in non-radioactive closed-loop systems not expected to be breached in a station blackout (with exception of lines that communicate directly with the containment atmosphere), and (5) all valves less than 3-inch nominal diameter. Valves not excluded based on the above criteria were termed "valves of concern."

The second step consisted of identifying valves of concern that need to be operated to cope with an SBO event to ensure that these valves can be operated independent of the preferred and Class 1E power supplies and have position indication that is independent of the preferred and Class 1E power supplies. For these valves it was confirmed that the valves can be powered from the AAC power source or can be closed manually via a handwheel, and have local mechanical indication.

The third step consisted of identifying valves of concern that need to be evaluated for containment integrity concerns during an SBO event to ensure that these valves can be operated independent of the preferred and Class 1E power supplies and have position indication that is independent of the preferred and Class 1E power supplies. For two of the four valves identified, it was confirmed that the valves can be powered from the AAC power source, can be closed manually via a handwheel, and have local mechanical indication. The “loss of all ac power” EOP contains instructions for closure of these valves if containment isolation is necessary. The other 2 valves identified are normally open under normal, shutdown, and accident conditions, and are not of concern for containment integrity during SBO conditions.

The SPU does not change any containment isolation requirements under SPU conditions. The SPU does not add or remove any containment isolation valves. The ability to close the identified valves of concern and the required position indication capability for these valves are not related to power level or other SPU-related changes. Accordingly, the evaluation of this issue for current plant conditions remains applicable for SPU conditions without change.

f. Reactor Coolant Inventory

An analysis was performed to determine the time to core uncovery for two postulated scenarios at SPU plant conditions. In the first scenario, no RCS makeup is assumed. In the second scenario, one charging pump with a minimum charging flow rate of 100 gpm is assumed to be available one hour after the onset of an SBO when the AAC power source is established. For both scenarios, an RCS leakage rate of 12 gpm (unidentified leakage, identified leakage, and primary to secondary leakage) per Technical Specification 3.4.6.2 was used. The Technical Specification limits on the RCS leakage rate of 12 gpm are not affected by the SPU. The assumption for RCP seal leakage has been updated to reflect new industry information. The analysis assumes a RCP seal leak rate of 21 gpm per pump seal for the first 30 minutes and 36.5 gpm per pump seal thereafter. The total assumed RCS leakage rate, including RCS leakage and RCP seal leakage from all four RCPs, is assumed to be 96 gpm for the first 30 minutes and 158 gpm thereafter.

For the first scenario, the analysis showed that with no RCS make-up it would take 4.7 hours to uncover the core. For the second scenario, the analysis showed that it would take 11.68 hours to uncover the core. Thus, at SPU conditions there is sufficient reactor coolant inventory during the first hour of the SBO event, when no RCS makeup is available, and during the remaining seven hours of the SBO event, when makeup is available, such that the core will remain covered for the 8 hour duration of an SBO event.

5. AFW System Flow Rate Requirements

The turbine-driven AFW pump is credited to support the decay and sensible heat removal design function during an SBO event. An analysis shows that, prior to SG depressurization, the turbine-driven AFW pump capacity (approximately 822 gpm at 1185 psig assuming degraded pump flow) will meet and exceed decay heat power at approximately 1.6 minutes after reactor trip at SPU conditions. The analysis also shows that, for a 2-hour RCS cooldown starting at 30 minutes after reactor shutdown, the available AFW flow from the turbine-driven AFW pump (e.g., 950 gpm at 60 minutes after shutdown, 690 gpm at 2 hours after reactor shutdown) exceeds the AFW flow required for decay heat and sensible heat removal at SPU conditions. Therefore, the turbine-driven auxiliary feedwater pump will continue to have sufficient capacity to support SBO scenario decay and sensible heat removal requirements at SPU conditions.

6. Plant Procedures

The “loss of all ac power” EOPs address operator actions associated with SBO diesel generator loading during an SBO event, operating ventilation systems, opening instrument panel doors, and precautions when performing local operations in the Main Steam Valve Building when the ventilation system is not operating.

As discussed in Item 3 above, for an SBO event at SPU conditions, there are no load increases that would affect the conclusions of the current SBO diesel generator loading analysis. Therefore, the SPU does not affect the “loss of all ac power” EOP instructions regarding SBO diesel generator loading.

As discussed in Item 4.d above, the SPU does not affect the results of the current plant analyses for maximum temperatures in the Instrument Rack Room during an SBO event. Therefore, the operator action specified in the “loss of all ac power” EOP for opening panel doors in this room is not affected by the SPU.

The SPU does not affect the operator actions in the “loss of all ac power” EOPs associated with providing ventilation to the Charging Pump Cubicle, Control Room, East and West Switchgear Rooms, and the East and West Rod Control Areas following an SBO event.

As discussed in Item 4.d above, the SBO analysis credits local operator actions in the Main Steam Valve Building that potentially has a hot ambient temperature when the ventilation system is not operating during an SBO scenario. Previous SBO assessments for the feasibility of Main Steam Valve Building local actions when the ventilation system is not operating are not impacted by the SPU.

2.3.5.3 Conclusion

DNC has reviewed the effects of the proposed SPU on the plant’s ability to cope with and recover from a station blackout event for the period of time established in the plant’s licensing basis. DNC concludes that the effects of the proposed SPU on station blackout have been adequately evaluated and that it has been demonstrated that the plant will continue to meet the current licensing basis with respect to 10 CFR 50.63 following implementation of the proposed SPU. Therefore, DNC finds that the proposed SPU is acceptable with respect to station blackout.

2.4 Instrumentation and Controls

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

2.4.1.1 Regulatory Evaluation

Instrumentation and Control (I&C) systems are provided 1) to control plant processes having a significant impact on plant safety, 2) to initiate the reactivity control system (including control rods), 3) to initiate the engineered safety features (ESF) systems and essential auxiliary supporting systems, and 4) for use to achieve and maintain a safe shutdown condition of the plant. Diverse instrumentation and control systems and equipment are provided for the express purpose of protecting against potential common-mode failures of instrumentation and control protection systems.

DNC reviewed the following systems for the proposed SPU to ensure that the systems and any changes necessary for the proposed SPU are adequately designed such that the systems continue to meet their safety functions:

- Reactor Trip System (RTS)
- ESF Actuation System (ESFAS)
- Safe Shutdown Systems
- Control Systems
- Diverse Instrumentation & Control (I&C) Systems

The DNC review was also conducted to ensure that failures of these systems do not affect safety functions.

The acceptance criteria are based on 10 CFR 50.55a (a) (1); 10 CFR 50.55a (h); and:

- GDC-1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, constructed, and tested to quality standards commensurate with their importance to performed functions.
- GDC-4, insofar as it requires that SSCs be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.
- GDC-13, insofar as it requires that instrumentation is provided to monitor variables and systems over their anticipated ranges for normal operation, anticipated operational occurrences, and for accident conditions as appropriate to ensure safety, including those variables and systems that can affect the fission process, reactor core integrity, the RCPB, and the containment and its associated systems. Appropriate controls should be provided to maintain these variables and systems within prescribed operating ranges.
- GDC-19, insofar as it requires that a control room be provided from which actions can be taken to safely operate the nuclear unit under normal conditions, and maintain it in a safe condition under accident conditions, including LOCAs.

- GDC-20, insofar as it requires that the protection system be designed to (1) automatically initiate the operation of appropriate subsystems, including the reactivity control systems, to ensure that acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and automatically initiate operation of systems and components important to safety.
- GDC-21, insofar as it requires that protection systems be designed for high functional reliability and in-service testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (1) no single failure results in loss of the protection function and (2) removal from service if any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated.
- GDC-22, insofar as it requires that the protection systems be designed to ensure that the effects of natural phenomena, and normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis.
- GDC-23, insofar as it requires that protection systems be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as system disconnection, loss of energy (e.g., electric power, instrument air), or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.
- GDC-24, insofar as it requires that the protection systems be separated from the control systems to the extent that a system satisfying all reliability, redundancy and independence requirements of the protection systems is left intact in the event of a failure of any single control system component or channel, or failure or removal from service of any single control system component or channel that is common to the control and protection systems. Protection and control system interconnection will be limited to ensure that safety is not significantly impaired.

Specific review criteria are contained in the SRP, Sections 7.0, 7.2, 7.3. 7.4, 7.7, and 7.8 and guidance provided in Matrix 4 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800 Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Sections 7.2, 7.3, 7.4, and 7.7 (all Rev. 02). Note that SRP Sections 7.0 and 7.8 are not part of the current MPS3 licensing basis. SRP Section 7.0 is merely an I&C review process overview. The AMSAC system was added after commercial operation and was not reviewed against the SRP Section 7.8 criteria discussed in RS-001. AMSAC meets the applicable requirements of 10 CFR 50.62 and the quality assurance requirements of NRC Generic Letter 85-06. As noted in FSAR Section 3.1, the MPS3 design bases are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 reactor protection, engineered safety feature actuation, and control systems regarding conformance to the following:

- GDC-1, Quality Standards and Records, is described in FSAR Section 3.1.2.1

  SSCs important to safety are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Quality standards applicable to safety related SSCs are generally contained in codes such as the ASME B&PV Code. The applicability of these codes is specifically identified throughout the FSAR and is summarized in FSAR Section 3.2.5.

  FSAR Chapter 17 provides direct reference to the Quality Assurance Program established to provide assurance that safety related SSCs satisfactorily perform their intended safety functions. The procedures for generating and maintaining appropriate design, fabrication, erection, and testing records are contained within the referenced documents.

- GDC-4, Environmental and Missile Design Bases, is described in FSAR Section 3.1.2.4

  SSCs important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

  SSCs important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in the FSAR Section 3.2.5.

  FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the SSC important to safety are designed.

- GDC-13, Instrumentation and Control, is described in FSAR Section 3.1.2.13

  Instrumentation and controls are provided to monitor and control neutron flux, control rod position, temperatures, pressures, flows and levels as necessary to assure that adequate plant safety can be maintained. Instrumentation is provided in the reactor coolant system, steam and power conversion system, the containment, engineered safety features systems, and other auxiliaries. Parameters that must be provided for operator use under normal operating and accident conditions are indicated in proximity with the controls for maintaining the indicated parameter in the proper range.

  The quantity and types of processing instrumentation provided ensures safe and orderly operation of all systems over the full design range of the plant. These systems are described in FSAR Chapters 6, 7, 8, 9, 11 and 12.

- GDC-19, Control Room, is described in FSAR Section 3.1.2.19

  The control room provided is equipped to operate the unit safely under normal and accident conditions. Its shielding and ventilation design permits continuous occupancy of the control room for the duration of a DBA without the dose to personnel exceeding 5 rem whole body. Based on 10 CFR 50.67, the applicable dose criterion was modified to 5 rem TEDE.

  The auxiliary shutdown panel located in the west switchgear room has equipment, controls and instrumentation to accomplish, in conjunction with controls and indication located on the adjacent 4160V emergency switchgear, a prompt hot shutdown and a safety grade cold shutdown. The panel is physically located outside of the control room. Thus, the uninhabitability of the control room would have no effect on the availability of the auxiliary shutdown panel and adjacent controls (FSAR Section 7.4.1.3).

  The design of the control building (FSAR Section 3.8.4), which houses the control room and the auxiliary shutdown panel area, conforms to Criterion 19. The control building ventilation system is described in FSAR Section 9.4.1. Control Room Habitability is discussed in FSAR Section 6.5.1. Fire protection systems are discussed in FSAR Section 9.5.1.

- GDC-20, Protection System Functions, is described in FSAR Section 3.1.2.20

  A fully automatic protection system, with appropriate redundant channels, is provided to cope with transients where insufficient time is available for manual corrective action. The design basis for all protection systems is IEEE Standard 279-1971 and IEEE Standard 379-1972. The reactor protection system automatically initiates a reactor trip when any variable exceeds the normal operating range. Setpoints are designed to provide an envelope of safe operating conditions with adequate margin for uncertainties to ensure that fuel design limits are not exceeded.

  Reactor trip is initiated by removing power to the rod drive mechanisms of all of the full length rod cluster control assemblies. This causes the rods to insert by gravity rapidly reducing reactor power output. The response and adequacy of the protection system have been verified by analysis of anticipated transients.

  The ESF actuation system automatically initiates emergency core cooling, and other safeguards functions, by sensing accident conditions using redundant analog channels measuring diverse variables. Manual action of safeguards equipment may be performed where ample time is available for operator action. The ESF actuation system automatically trips the reactor on manual or automatic SI signal generation.

- GDC-21, Protection System Reliability and Testability, is described in FSAR Section 3.1.2.21

  The protection system is designed for high functional reliability and in-service testability. Compliance with this criterion is discussed in detail in FSAR Sections 7.2.2.2.3 and 7.3.2.2.5.

- GDC-22, Protection System Independence, is described in FSAR Section 3.1.2.22

  Protection system components are designed and arranged so that the environment accompanying any emergency situation in which the components are required to function does not result in loss of the safety function. Various means are used to accomplish this. Functional diversity has been designed into the system. The extent of this functional diversity has been evaluated for a wide variety of postulated accidents. Diverse protection functions automatically terminate an accident before intolerable consequences could occur. FSAR Section 7.1.2.1.8 provides details of ESF system diversity.

Automatic reactor trips are based on process parameters and neutron flux measurements. Trips on process parameters include RC loop temperature measurements, pressurizer pressure and level measurements, and RCP underspeed trip. Trips may also be initiated manually or by a SI signal. FSAR Section 7.2 describes all the trips and provides further details.

High quality components, conservative design and applicable quality control, inspection, calibration and tests are utilized to guard against common-mode failure. FSAR Sections 3.10 and 3.11 provide details concerning qualification testing. Qualification testing is performed on the various safety systems to demonstrate functional operation at normal and post-accident conditions of temperature, humidity, pressure and radiation for specific periods, if required. Typical protection system equipment is subjected to type tests under simulated seismic conditions using conservatively large accelerations and applicable frequencies. The test results indicate no loss of the protection function.

- GDC-23, Protection System Failure Modes, is described in FSAR Section 3.1.2.23

  The protection system is designed with due consideration of the most probable failure modes of the components under various perturbations of the environment and energy sources. FSAR Sections 7.2 and 7.3 discuss the protection system.

- GDC-24, Separation of Protection and Control Systems, is described in FSAR Section 3.1.2.24

  The protection system is separate and distinct from the control systems. Control systems may be dependent on the protection system in that control signals are derived from protection system measurements, where applicable. These signals are transferred to the control system by isolation devices that are classified as protection components. The adequacy of system isolation is verified by testing under conditions of postulated credible faults. The failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel, which is common to the control and protection systems, leaves intact a system that satisfies the requirements of the protection system. Distinction between channel and train is made in this discussion. The removal of a train from service is allowed only during testing of the train. FSAR Chapter 7 gives further details.

FSAR Chapter 7 discusses I&C systems. The primary purpose of the I&C systems is to provide automatic protection and exercise proper control over unsafe and improper reactor operations during steady state and transient power operations (ANS Conditions I, II and III), and to provide initiating signals to mitigate the consequences of faulted conditions (ANS Condition IV). ANS conditions are discussed in the FSAR Chapter 15.

Other FSAR sections that address the design features and functions of plant safety related systems and instrumentation include:

- FSAR Section 7.1.1.1, Safety Related Systems, describes the MPS3 instrumentation that is required to function to achieve the system responses assumed in safety evaluations, and those instruments needed to safely shut down the plant.
- FSAR Section 7.1.2, Identification of Safety Criteria, provides the design bases in FSAR Section 7.1.2.1 for the systems listed in FSAR Section 7.1.1.1 (RTS, ESFAS, I&C Power Supply System).
- FSAR Section 7.2, Reactor Trip System, provides the system description (including functional performance requirements, reactor trips, interlocks and setpoints), design bases, and analyses (including control and protection system interaction).
- FSAR Section 7.3, Engineered Safety Features System, provides the system description, design bases (including limits, margins and setpoints) and analyses (including control and protection system interaction).
- FSAR Section 7.4, Systems Required for Safe Shutdown, identifies the minimum systems required to achieve and maintain hot standby and cold shutdown without offsite power, and with an event initiated by a single random failure.
- FSAR Section 7.5, Safety Related Display Instrumentation, identifies the MPS3 NSSS and BOP instruments subject to the requirements of RG 1.97, Post Accident Monitoring. MPS3 meets the intent of RG 1.97, Rev. 2. FSAR Section 7.5, Appendix 7.5A, lists areas where MPS3 has deviated from RG 1.97 Rev. 2 requirements, and the bases for such deviations. FSAR Section 7.5.1.1 discusses the SPDS. The SPDS provides a concise display of critical plant variables to control room operators to aid them in rapidly determining the plant safety status.
- FSAR Section 7.6, All Other Systems Required for Safety, describes the power supplies, instrumentation and interlocks required for overpressure protection during low power operation; RCS loop isolation valve and accumulator MOV interlocks; RHR system isolation valves and interlocks; refueling interlocks; fuel pool cooling and purification system; containment leakage monitoring system; interlocks for RCS pressure control during low temperature operation; heat tracing of safety related systems; and the Shutdown Margin Monitor.
- FSAR Section 7.7, Control Systems Not Required for Safety, provides a description of the reactor control system, rod control, plant control signals for monitoring and indicating, plant control system interlocks, pressurizer pressure and water level control, SG water level control, steam dump control, and incore instrumentation. Also included is a description of the plant response to design loading and unloading.
- FSAR Section 7.8, Anticipated Transient Without Scram Mitigation System Actuation Circuitry, provides a description of the AMSAC system that provides a backup to the RPS and ESFAS for initiating turbine trip and auxiliary feedwater flow in the event of an anticipated transient (e.g., complete loss of main feed water).

The I&C systems and components were evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005 defined the scope of license renewal. NUREG-1838 Sections 2.5 and 3.6 are applicable to I&C systems and components.

2.4.1.2 Technical Evaluation

2.4.1.2.1 Introduction

The reactor trip system, engineered safety features system, display instrumentation, reactor control systems, and AMSAC are impacted by the increase in reactor thermal power from 3411 MWt to 3650 MWt.

2.4.1.2.2 Input Parameters and Assumptions

The SPU design parameters are identified in Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1. The initial best estimate nominal 3650 MWt full power operating parameters and associated values are listed in Table 2.4.1-1 below. These values are current best estimates and may change, as turbine and core design are refined.

2.4.1.2.3 Description of Analyses and Evaluations

The effects of the reactor thermal power increase have been evaluated for normal operation, operational transients, and accident conditions described in FSAR Sections 6.0, Engineered Safety Features, 7.7, Control Systems Not Required For Safety, and 15, Accident Analyses. These evaluations used the most conservative combination of NSSS design values from Section 1.1, Table 1-1. The analyses included changes to the Reactor Trip and ESFAS analytical limits described in Section 2.4.1.2.3.1 and Section 2.4.1.2.3.2. The transient and accident analyses results are described in the following Licensing Report Sections:

- Section 2.4.2, Plant Operability
- Section 2.8.5, Accident and Transient Analyses

The analyses identified changes required to ensure DNB, RCS pressure, and main steam system pressure remain within the allowable design margins, and the response to design basis operational transients remains acceptable. These changes are described in Section 2.4.1.2.3.1, Reactor Trip System, Section 2.4.1.2.3.2, Engineered Safety Features System, Section 2.4.1.2.3.6, Control Systems Not Required For Safety, and Section 2.4.1.2.3.7, Anticipated Transients Without Scram Mitigation System Actuation Circuitry.

Using the best estimate data from SPU heat balances, BOP instrumentation was evaluated to determine required changes using the following methodology:

- Systems were analyzed to determine if the current system process conditions changed as a result of the SPU.
- For those BOP systems where process conditions changed at SPU conditions, the system instrumentation was evaluated to determine if the instrumentation ranges, scaling, and setpoints remained adequate.

- For those instruments where the current instrumentation ranges, scaling, or setpoints were not adequate to support SPU conditions, new ranges, scaling, setpoints, or instrument replacement were identified.

The following BOP system instrumentation were evaluated:

- Main Steam
- Extraction Steam
- Condensate and Feedwater
- Auxiliary Feedwater & Recirculation
- Steam Generator Blowdown
- Feedwater Heater and MSR Drains
- Service Water
- Component Cooling Water
- Condenser & Circulating Water
- Containment Spray
- Fuel Pool Cooling & Purification
- Main Turbine Control

With the exception of the instrumentation listed below, the BOP instrumentation ranges and setpoints are adequate for SPU conditions. The following instrumentation changes are described in Section 2.4.1.2.3.8, Other Systems.

- Moisture separator reheater steam flow instrumentation
- Main feedwater pumps speed control instrumentation
- Turbine controls rescaling and meter range changes

Technical Specification Limiting Safety System Setting (LSSS) values and trip setpoint values are derived from analytical values used in the analyses described above, corrected to account for the specific instrument or control system uncertainty. DNC calculates instrument uncertainty and setpoints using the methodology in WCAP – 10991 Rev. 5 (Reference 1). This methodology is conservative with respect to ISA-67-04 as described in the proposed revision to Technical Specifications dated October 15, 1997 and supplemented by letters dated January 23 and April 8, 1998. The NRC approved this request as Amendment 159 dated May, 26, 1998.

2.4.1.2.3.1 Reactor Trip System

The RTS is described in FSAR Section 7.2, Reactor Trip System (RTS), and includes the functional performance requirements, reactor trips, interlocks, setpoints, design bases and analyses. Reactor trips protect against RCS damage caused by high system pressure, and fuel rod cladding damage caused by a departure from nucleate boiling. The basic reactor tripping philosophy defines a region of power and coolant temperature and pressure conditions allowed by the primary trip functions (overpower ΔT trip, over temperature ΔT trip, and nuclear overpower trip). The trip settings prevent any combination of power, temperature, and pressure that results in a departure from nucleate boiling with all reactor coolant pumps in operation.

Additional reactor trips such as a high pressurizer pressure trip, low pressurizer pressure trip, high pressurizer water level trip, low RCS flow trip, steam-generator low-low water level trip, low RCP shaft speed trip, turbine trip, safety injection trip, nuclear instrumentation source and intermediate range trips, and manual trip are provided to back up the primary trip functions for specific accident conditions and mechanical failures.

Technical Specification Table 2.2-1 lists the reactor trips:

- Manual reactor trip
- Power range neutron flux (high and low setpoints)
- Power range neutron flux (high positive rate)
- Intermediate range neutron flux
- Source range neutron flux
- Overtemperature T (OTΔT)
- Overpower T (OPΔT)
- Pressurizer pressure – low
- Pressurizer pressure – high
- Pressurizer water level - high
- Reactor coolant flow – low
- Steam generator water level low-low
- General warning alarm
- RCP low shaft speed
- Turbine trip
- Safety injection (from ESF)

Technical Specification Table 2.2-1 lists the RTS interlocks:

- Permissive P-6
- Permissive P-7
- Permissive P-8
- Permissive P-9
- Permissive P-10
- Permissive P-13

The analyses concluded that the following RTS analytical limit, instrument scaling, and setpoint changes described below are necessary to ensure the RTS will continue to satisfy its design functions at SPU conditions or will provide additional operational margin for the identified protective function. A modification is being made to the overtemperature ∆T and overpower ∆T functions to add a four (4) second filter to the T_{hot} signal prior to the modules that calculate T_{avg} and ∆T, and remove the rate lag compensation for the T_{avg} input to overpower ∆T. These modifications are described below. There are no other changes to the RTS functions and interlocks listed above as a result of the SPU.

Nuclear Instrumentation

The SPU redefines the 100 percent power neutron flux levels, which impacts the flux level to percent power relationship (rated thermal power) for the intermediate range and power range nuclear instruments. During power ascension, as well as upon reaching the uprated power level, reactor physics testing will confirm the flux to power relationship and the intermediate and power range nuclear instrumentation will be rescaled as required. Since the source range nuclear instrumentation is deenergized well below the power range during reactor startup and the reactor protection setpoint is in counts per second, there are no required changes to the source range instrumentation settings.

The SPU accident and transient analyses determined that for some accidents, the analytical limit for the power range high power trip must be reduced from the current 118 percent to 116.5 percent rated thermal power (RTP) (Section 2.8.5.4.2, Uncontrolled Rod Cluster Control Assembly Withdrawal at Power). Although the power range high power trip Safety Analysis Limit (SAL) is decreasing to 116.5 percent, the uncertainty analysis for the current nominal trip setpoint of 109 percent of RTP has adequate margin to accommodate the new SAL limit without change.

The accident and transient analyses determined that the analytical limit of 35 percent of RTP for the power range low power reactor trip remained adequate for SPU conditions. Therefore, the current power range low power reactor trip setpoint of 25 percent is also adequate at SPU conditions. The intermediate range neutron flux trip is not explicitly credited for actuation in the Safety Analysis and therefore there is no Safety Analysis Limit associated with this functions. As such, the trip setpoint of 25 percent of RTP is adequate for SPU conditions.

RCS Temperature Instrumentation

No changes were necessary for the T_{hot}, T_{cold}, T_{avg} and T instrument ranges at SPU conditions. The existing values provide the required indication, core DNB protection, and plant response during accidents and transients over the entire operating range at SPU conditions.

T_{avg} and T associated alarm setpoints will be recalibrated as necessary to essentially maintain the same margin to alarm as existed prior to the SPU.

Overtemperature ∆T/Overpower ∆T

As part of the overtemperature ∆T (OT∆T) and overpower ∆T (OP∆T) optimization, a 4 second filter is being added to the T_{hot} input, prior to the modules that calculate T_{avg} and ∆T, to smooth out temperature spikes observed in the T_{hot} signals. The filters allows additional optimization of the OT∆T/OP∆T settings to improve the trip margins for the OT∆T and OP∆T reactor trips, and also add stability to the rod control system. In addition, the rate lag compensator card (TY-412S) for T_{avg} input to the OPΔT will be eliminated from the control system.

The OTΔT/OPΔT trip setpoint constant values are listed in the cycle specific COLR. For the initial SPU startup, the OTΔT/OPΔT trips will be recalibrated with the OTΔT/OPΔT constants changed as shown in Tables 2.4.1-2 and 2.4.1-3 respectively.

P-7 Permissive Changes

The P-7 permissive is used to block the low pressurizer pressure, high pressurizer level, low RCS flow, and RCP low shaft speed reactor trips during low power or

startup operation. P-7 is derived from a bistable circuit currently set at 11 percent RTP as measured by power range nuclear instrumentation (P-10) and 10 percent RTP (turbine impulse pressure equivalent) as measured by first stage turbine pressure (P-13). Power range nuclear instrumentation calibration is discussed above under Nuclear Instrumentation. The turbine first stage pressure input will be recalibrated to actuate at the value consistent with the new 0 percent - 100 percent power nominal turbine first stage pressure range of approximately 0 - 710 psia. If during SPU power ascension testing a more accurate nominal turbine first stage pressure range is determined, the turbine first stage pressure input will be recalibrated accordingly.

P-8 Permissive Change

The P-8 permissive is used to block a single loop low RCS flow reactor trip when three out of four power range nuclear instruments are less than the permissive setpoint, currently 37.5 percent RTP. The single loop low RCS flow trip is unblocked when two out of four power range nuclear instruments indicate greater than the P-8 setpoint. The current setpoint was established based on N-1 operation, which is no longer part of the MPS3 licensing bases. The analyses performed for SPU conditions is based on N loop operation and determined that an upper limit of 60 percent power is required to ensure all accidents and transients impacted by RCS flow maintain DNB within acceptable limits. (Section 2.8.5.3.1, Loss of Forced Reactor Coolant Flow). A 10 percent allowance was conservatively applied in the analysis to establish a new nominal trip setpoint of 50 percent RTP with an allowable value of 50.6 percent RTP. Therefore, the present P-8 Technical Specification nominal trip setpoint will be increased from the current value of 37.5 percent RTP to 50 percent RTP with an allowable value of 50.6 percent RTP.

2.4.1.2.3.2 Engineered Safety Features System

The ESFAS is described in FSAR Section 7.3, Engineered Safety Features System, and includes the functional performance requirements, interlocks, setpoints, design bases and analyses. The engineered safety features provide protection to prevent or mitigate damage to the core and reactor coolant system, and ensure containment integrity in the event of a loss-of-coolant accident or a secondary line break. The engineered safety features maintain the reactor in a shutdown condition, provide sufficient core cooling to limit the extent of fuel and fuel cladding damage, and ensure containment structure integrity. These functions rely on the ESFAS and associated instrumentation and controls.

Technical Specification Table 3.3-4 lists the following ESFAS functions:

- Safety injection

- Containment spray (CDA)
- Containment isolation
- Steam line isolation
- Turbine trip and feedwater isolation
- Auxiliary feedwater actuation
- Control building isolation
- Loss of power
- Emergency generator load sequencer

Technical Specification Table 3.3-4 lists the ESFAS interlocks:

- Permissive P-4
- Permissive P-11
- Permissive P-12
- Permissive P-14

The analyses concluded that the ESFAS analytical limit changes described below are necessary to ensure that the ESFAS will continue to satisfy its design functions at SPU conditions. A modification is being made to add a new cold leg injection permissive to the cold leg injection valve control logic. A modification is being made to the control building emergency ventilation system to automatically initiate pressurized filtration upon receipt of a CBI signal versus the present manual initiation design. These modifications are described below. There are no other changes to the ESFAS functions and interlocks listed above as a result of the SPU.

Pressurizer Pressure Low SI

The SPU transient analyses and containment analyses are based upon an analytical limit for the pressurizer low pressure safety injection setpoint of 1700 psia. In the current analyses, different values were used for the various transient and containment analyses, ranging from 1600 psia to 1700 psia. Thus, for some analyses, the SAL is increasing from 1600 psia to 1700 psia. The current nominal safety injection actuation setpoint of 1892 psia has adequate margin to accommodate the SAL of 1700 psia and will not change.

Cold Leg Injection Permissive (P-19)

A new permissive (P-19) will be added to monitor low RCS pressure. The permissive will be derived utilizing the existing low pressurizer pressure reactor trip two out of four bistable trip logic and will have the same setpoint as that function. Within the MPS3 solid state protection cabinets, this signal will be separated from the reactor trip function logic to develop the low RCS pressure, cold leg injection permissive. The cold leg injection permissive relay contacts will be placed in series with the safety injection relay contacts in the control logic for the cold leg injection valves, to permit them to open automatically upon receiving both the safety injection signal and the cold leg injection permissive. (Section 2.8.5.5, Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory) Using the low pressurizer pressure reactor trip bistable trip logic helps to maintain diversity from the low pressurizer pressure safety injection bistable trip logic to the extent possible.

Control Building Automatic Filtered Pressurization Upon CBI

To reduce the control room radiological consequences of a fuel handling accident, a modification will be made to the control building emergency ventilation system to automatically initiate the filtered pressurization mode of operation upon receipt of a CBI signal. The modification includes changing the failure mode position of the control building ventilation system outside air inlet valves from their present fail closed mode to fail open, and revising the CBI signal to open the valves should they be closed when the CBI signal is received. The emergency ventilation system dampers that presently require manual alignment to initiate the pressurized filtration mode of operation will be modified to automatically align upon receipt of a CBI signal. The control room emergency ventilation system fan control circuits will be modified to ensure proper operation upon receipt of the CBI, once all the required dampers have properly aligned for the filtered pressurization mode from the CBI signal. (Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms).

2.4.1.2.3.3 Systems Required For Safe Shutdown

The systems required for safe shutdown are described in FSAR Section 7.4, Systems Required For Safe Shutdown. There are two shutdown conditions addressed in this section: hot standby and cold shutdown. Both conditions can be achieved with or without offsite power and with an event initiated by a single random failure. There were no instrumentation or control changes required for systems and components contained in this FSAR Section, except as follows: Reactor Plant Component Cooling Water System Instrumentation - The residual heat removal system is evaluated in Section 2.8.4.4, and a required design change in reactor plant component cooling water system maximum operating temperature during cooldown operation is identified. Supporting setpoint increases on the residual heat removal heat exchanger's reactor plant component cooling water system return line temperature instrumentation (3CCP-TS65A2/B2 and 3CCP*TS65A/B) are required. This instrumentation provides a high temperature alarm and also opens the residual heat removal heat exchanger bypass flow control valves (3RHS*FCV618/619) upon increasing temperature. The specific proposed setpoints are identified in Table 2.8.4.4-2.

2.4.1.2.3.4 Safety-Related Display Instrumentation

Safety-related display instrumentation is described in FSAR Section 7.5, Safety-Related Display Instrumentation. This section also identifies NSSS and BOP instruments subject to the requirements of RG 1.97. This instrumentation is used by the operators throughout all operating conditions including, anticipated operational occurrences, accidents and post-accident.

Technical Specification Table 3.3-10 lists the following accident monitoring instrumentation parameters:

- Containment pressure (normal and extended range)
- Reactor coolant outlet temperature – T_{hot} (wide range)
- Reactor coolant inlet temperature – T_{cold} (wide range)

- Reactor coolant pressure (wide range)
- Pressurizer water level
- Steam line pressure
- SG water level (narrow and wide range)
- RWST water level
- DWST water level
- Auxiliary feedwater flow rate
- RCS subcooling margin monitor
- Containment water level (wide range)
- Core exit thermocouples
- Containment Area – High Range Radiation Monitor
- Reactor Vessel Water Level
- Neutron Flux

The Safety Parameter Display System (SPDS) provides a concise display of critical plant variables to control room operators. This information aids the operators in rapidly and reliably determining the plant safety status.

Other than minor rescaling, as described within this LR, to accommodate changes in process condition resulting from the SPU conditions, there are no changes to the SPDS or accident monitoring instrumentation listed above.

Instrumentation required for Post Accident Monitoring (RG 1.97) was reviewed to evaluate SPU condition changes on required measurement ranges and extended range capabilities. No impacts to the existing RG 1.97 instrumentation were identified as a result of the SPU conditions.

2.4.1.2.3.5 All Other Systems Required For Safety

Other systems required for safety are described in FSAR Section 7.6, Systems Required For Safe Shutdown. This section includes the following systems and components:

- RHR isolation valves
- Refueling interlocks
- Accumulator motor-operated valves
- RCS loop isolation valve interlock
- Fuel pool cooling and purification system
- Containment leakage monitoring system
- Interlocks for RCS pressure control during low temperature operation

- Heat tracing of safety-related systems
- Shutdown margin monitor

There were no instrumentation or control changes required for systems or components contained in this FSAR Section.

2.4.1.2.3.6 Control Systems Not Required For Safety

FSAR Section 7.7, Control Systems Not Required For Safety, defines the general design objectives of the plant control systems. The reactor control systems include the following design attributes:

- Establish and maintain power equilibrium between primary and secondary systems during steady state operation.
- Constrain operational transients so as to preclude a reactor trip and re-establish steady state operation.
- Provide the plant operator with monitoring instrumentation that includes all required system input and output control parameters and the capability to assume manual control of the system.

The control systems described in FSAR Section 7.7 perform the following functions:

- Reactor control system (automatic rod control)
- Rod control system
- Plant signals for monitoring and indicating
- Plant control system interlocks
- Pressurizer pressure control
- Pressurizer water level control
- Steam Generator water level control
- Steam dump control
- Incore instrumentation

The current design basis operational transients are described in FSAR Section 7.7.2. MPS3 is able to sustain the following transients without initiating a reactor trip or an ESF actuation signal.

- Step change of ± 10 percent over the 15 to 100 percent power range without steam dump
- Ramp loading and unloading of 5 percent/minute over the 15 to100 percent power range
- Step load decrease of up to 50 percent rated power with steam dump and auto rod control (insertion)
- Turbine trip with steam dump when the plant is below P-9 setpoint

Following SPU implementation, the design basis operational transients are defined as follows:

- Step change of ±10 percent over the 15 to 100 percent power range without steam dump
- Ramp loading and unloading of 5 percent/minute over the 15 to 100 percent power range
- Rapid ramp load decrease equivalent to 50 percent of rated power at a maximum turbine unloading rate of 200 percent/minute.
- Turbine trip with steam dump when the plant is below P-9 setpoint

In FSAR Section 10.4.4, Turbine Bypass System, the large load rejection transient is described as a step load reduction of up to 50 percent without a reactor or turbine trip. For the SPU, the 50 percent step load reduction transient is being revised to a rapid ramp load reduction equivalent to 50 percent of SPU rated power at a maximum turbine unloading rate of 200 percent/minute. This change in load rejection from a step change to a rapid ramp load decrease redefines the load rejection in a manner that more closely approximates the actual transient, and is consistent with power uprates previously performed on other Westinghouse plants.

The turbine trip without reactor trip analysis at SPU conditions showed that with the present load rejection controller setpoints, the pressurizer PORVs could be challenged. Consequently, the load rejection controller setpoints will be modified to maintain peak pressurizer pressure below the PORV setpoint. Refer to Table 2.4.1-4 below for the revised load rejection controller setpoints.

The analysis of the plant response to several design basis operational transients at SPU conditions concluded that the following control system changes are necessary as a result of the SPU.

Rod Control System Changes

The rod control system responds to changes in RCS temperature and secondary load as measured by T_{avg} instrumentation and turbine first stage pressure instrumentation (T_{ref}). The rod control system also contains an anticipatory circuit that compares reactor power (as measured by nuclear instrumentation), to turbine power (as measured by turbine first stage pressure instrumentation). Because the nuclear instrumentation is not qualified for the environment resulting from a steam line break inside containment, it is postulated that the nuclear instrumentation can fail such that the rod control system would withdraw control rods, increasing reactor power. A steam line break coincident with rod withdrawal is currently the limiting MPS3 DNBR event. In anticipation that the SPU would result in a loss of DNBR margin, a modification will be made to the rod control system to eliminate the automatic rod withdrawal capability. This modification has been implemented at a number of utilities to resolve this issue. The steam line break analysis credits the elimination of automatic rod withdrawal. (Section 2.8.5.1.2, Steam System Piping Failures Inside and Outside Containment)

The MPS3 design bases and expected operational transients have been evaluated for the elimination of the automatic rod withdrawal capability, and no adverse system responses were identified at SPU conditions.

Pressurizer Level Program

The pressurizer level control system maintains the pressurizer level within a programmed band. The programmed pressurizer level value varies with T_{avg} (circuit uses auctioneered high T_{avg} to establish the program level value). The programmed level is designed to accommodate RCS shrink and swell associated with changes in RCS temperature, maintain sufficient margin above the low level heater-cutoff and letdown isolation setpoint of 22 percent, and to maintain sufficient steam volume to ensure the pressurizer does not go water solid during accidents and transient conditions.

To accommodate increased shrink and swell associated with SPU conditions, the current 28 percent–61.5 percent program band is being changed to a new pressurizer level program of 28 percent–64 percent. When T_{avg} is ≤557°F, the pressurizer level program is constant at 28 percent span. When T_{avg} is ≥587°F, the pressurizer level program is constant at 64 percent span. The level program varies linearly between 557°F and 587°F.

The impact of the new 64 percent level has been evaluated for pressurizer overfill and drain down events. The addition of the cold leg injection permissive will eliminate the most limiting overfill event. (Section 2.8.5.5, Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory) The evaluation of the next most limiting overfill event, chemical and volume control system equipment failures, concludes that the new pressurizer level program is acceptable for SPU conditions. The most limiting drain down event is the Fire Protection Program BTP 9.5-1 requirement to maintain pressurizer level on scale during a loss of all charging due to a fire in the charging pump cubicle, or fire in the control room, cable spreading room, or instrument rack room. The evaluation of this event concludes that the new pressurizer level program is acceptable for SPU conditions. (Section 2.5.1.4, Fire Protection)

Analyses described in Section 2.4.2, Plant Operability and Section 2.8.5, Accident and Transient Analyses, are based on the new nominal pressurizer level program.

Turbine Bypass System (Steam Dump)

The steam dump system discharges a portion of main steam flow directly to the main condenser, bypassing the turbine. The system is designed to remove RCS sensible heat for a large rapid load reduction or reactor trip, and during plant start-up and shutdown to control steam generator pressure. With steam dump unavailable, a large rapid turbine load reduction could result in the undesirable lifting of pressurizer and main steam safety valves. The steam dump system evaluation is described in Section 2.5.5.3, Turbine Bypass, and Section 2.4.2, Plant Operability.

To allow steam dump operation, the main condenser must be available as defined by adequate condenser vacuum and operating circulating water pumps. The steam dump valves (Banks 1 to 3) are armed based on a rapid decrease in turbine first stage pressure (equivalent to >10 percent load decrease). The dump valves either modulate open or are tripped open based on the magnitude of error (T) between the auctioneered high T_{avg} value and the reference temperature (T_{ref}) programmed off the turbine first stage pressure.

The existing steam dump valves are designed to pass nominally 40 percent of main steam flow at the current RTP. In conjunction with the rod control system, which accommodates nominally

10 percent of the load reduction, the steam dump system permits the NSSS to withstand a large load rejection equivalent to 50 percent RTP at a maximum turbine unloading rate of 200 percent per minute or a turbine trip at less than 50 percent RTP. The steam dump system can continue to meet these design requirements at SPU conditions with the steam dump control system (load rejection controller) setpoint changes shown in Table 2.4.1-4 below.

Turbine First Stage Pressure Instrumentation

When the turbine generator is on line, turbine first stage pressure increases essentially linearly from 0 percent - 100 percent turbine load and provides a close correlation of secondary power to reactor power. This allows turbine first stage pressure to be used as a reliable input demand signal or permissive to the various reactor control systems between 0 percent and 100 percent reactor power. The pre-SPU 0 percent - 100 percent turbine load turbine first stage correlates to 0 - 650 psia. For SPU, a new 0 percent - 100 percent power nominal first stage turbine pressure of approximately 0 – 710 psia is expected. Actual full power turbine first stage pressure may change slightly as the steam cycle design is refined and instrument calibrations will be revised accordingly.

The existing turbine first stage pressure transmitters and associated indications will be recalibrated and scaled to a range that will encompass the new first stage pressure value. The inputs to each of the following systems will be recalibrated to respond at the appropriate value for the new 0 - 100 percent power nominal turbine first stage pressure of 0 - 710 psia.

- AMSAC - arm/disarm circuit permissive C-20 at first stage pressure equivalent to 40 percent reactor power
- P-7 Permissive- in conjunction with P-10, bypasses low pressurizer pressure, high pressurizer water level, low RCS flow, and RCP low shaft speed reactor trips
- Rod Control power mismatch and non linear gain controls
- Steam Generator level control
- Load reject steam dump control
- Reactor control T_{ref}
- Block auto rod withdrawal C-5 permissive

2.4.1.2.3.7 Anticipated Transients Without Scram Mitigation System Actuation Circuitry

The AMSAC provides a backup to the RTS and ESFAS for initiating turbine trip and auxiliary feedwater flow in the event of an anticipated transient (e.g., complete loss of main feedwater). The AMSAC is not safety-related and not required to meet IEEE 279-1971. The AMSAC is independent of and diverse from the RTS and ESFAS, with the exception of the final actuation devices.

Changes are being made to the C-20 permissive scaling. C-20 automatically arms and disarms AMSAC at a turbine first stage pressure equivalent to 40 percent reactor power. The C-20 permissive will be recalibrated to arm/disarm at the appropriate turbine first stage pressure consistent with the new 0 percent–100 percent power nominal turbine first stage pressure range for SPU full load values 0–710 psia.

2.4.1.2.3.8 Other Systems

The changes identified below are being made to systems that are not described in FSAR Sections 7.2 through 7.8.

Main Steam System Instrumentation

The main steam evaluation determined that the moisture separator reheater steam supply increases approximately 5 percent. (Section 2.5.5.1, Main Steam, Table 2.5.5.1-1) As a result, the measurement range of the moisture separator reheater steam supply flow instrument loops will be rescaled to accommodate this increased flowrate.

Condensate and Feedwater System Instrumentation

The condensate and feedwater system evaluation is described in Section 2.5.5.4, Condensate and Feedwater. As a result of that evaluation, the two main feed pump turbine speeds will increase and the speed control loop differential pressure input will change from the existing 140 psid (nominal) to approximately 212 psid (nominal) for the SPU conditions. (Section 2.5.5.4, Condensate and Feedwater)

Turbine Controls and Instrumentation

Changes in the main steam system and turbine steam path pressures resulting from SPU conditions will require the turbine control pressure instrumentation rescaling, pressure meter scales replacement, and modifying the control card settings for control valve position demand.

Plant Calorimetric

The reactor coolant flow calorimetric uncertainty analysis for SPU conditions identified a requirement to perform the calorimetric at no less than 90 percent RTP to maintain RCS flow accuracy within the Technical Specification assumed uncertainty of 2.4 percent RCS flow. The plant Technical Specification is being revised to change the present value of 75 percent to the new value of 90 percent RTP.

The calorimetric power measurement uncertainty has been evaluated for SPU conditions and was found to meet the accuracy requirements assumed in the revised safety analysis.

Miscellaneous

The following is a list of minor rescaling and setpoint changes due to other SPU condition changes:

- Pressurizer relief tank high and low level alarm setpoints were changed due to the increase in the pressurizer level program.

2.4.1.2.3.9 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for Instrumentation and Controls. As stated in Section 2.4.1.1, I&C systems and components are within the scope of the License Renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The SPU does not add any new or previously unevaluated materials to the system. The impact of SPU environmental conditions on I&C components is evaluated in Section 2.3.1, Environmental Qualification of Electrical Equipment "Environmental Qualification of Electrical Equipment." The I&C components remain qualified under SPU conditions and there is no impact on maintenance schedules. Thus, no new aging effects requiring management are identified. Therefore, the existing license renewal evaluations remain valid at SPU conditions.

2.4.1.2.4 Results

The Instrumentation & Control system changes are the result of accident and transient analyses, and system evaluations based on the SPU conditions. The changes described above ensure that DNB values remain within acceptable limits, and the RCS and main steam pressure boundaries are maintained within the design values. The evaluations concluded that the identified instrumentation and controls changes, recalibration, and rescaling ensures the instrumentation will continue to provide the required protective functions and support plant process parameter monitoring during normal, transient, and accident conditions.

2.4.1.3 Conclusion

DNC has evaluated the effects of the proposed SPU on the functional design of the reactor trip system, engineered safety features actuation system, safe shutdown system, and control systems. DNC concludes that the evaluation adequately accounts for the effect of the proposed SPU on these systems, and that the necessary changes are consistent with the MPS3 design basis. DNC concludes that the instrumentation and control systems will continue to meet the MPS3 current licensing basis with respect to the requirements of 10 CFR 50.55a(a) (1), 10 CFR 50.55(a) (h), and GDCs -1, -4, -13, -19, -20, -21, -22, -23, and -24. Therefore, DNC finds the proposed SPU acceptable with respect to instrumentation and control systems.

2.4.1.4 References

1. WCAP–10991, Rev. 5, "Millstone Nuclear Power Station Unit 3 24 Month Fuel Cycle Evaluation," August 1997

2. Amendment 159, "Issuance of Amendment – Millstone Nuclear Power Station, Unit No. 3 (TAC No. M99796), "May 26, 1998

Table 2.4.1-1
Initial Best Estimate Nominal 3650 MWt Full Power Operating Parameters

Parameter	SPU Value
NSSS Power (core Power + RCP Heat) (MWt)	3666
Main Steam Flow (total flow) (lbm/hr) – max.	16.32×10^6
Main Steam Flow (per SG) (lbm/hr) – max.	4.08×10^6
Main Feedwater Flow (no blowdown included) (lbm/hr)	16.32×10^6
Main Feedwater Flow (per SG - no blowdown included) (lbm/hr)	4.08×10^6
Main Steam Pressure (psig)	979.3
Rated Full Power ΔT (°F)	66.2°F–68.2°F
Rated Full Power Average T_{avg} (°F)	571.5–589.5
No Load Average T_{avg} (°F)	557
Pressurizer Level program 0% - 100% (% level)	28%–64%
Full Load Turbine First Stage Pressure (psia) (*subject to final HP turbine design)*	710
Feedwater Temperature (°F)	390–445.3

Table 2.4.1-2
Overtemperature ΔT (OTΔT) Trip

Parameter	Current	SPU
Safety Analysis Analytical Limit – K1	1.41	1.370
Constant K1	1.27	1.2
Constant K2	0.0245/°F	0.025/°F
Constant K3	0.00108/psi	0.00113/psi
f(ΔI) deadband	-35% to +3%	-18% to +10%
f(ΔI) negative slope	-1.83%/%ΔI	-3.75%/%ΔI
f(ΔI) positive slope	+2.05%/%ΔI	+2.14%/%ΔI
T_{hot} Filter Constant*	N/A*	4 seconds
[* Note: There is a 4 second ΔT filter]		

Table 2.4.1-3
Overpower ΔT (OPΔT) Trip

Parameter	Current	SPU
Safety Analysis Analytical Limit - K4	1.18	1.173
Constant K4	1.13	1.10
Constant K5	0.02/°F	0.0/°F
Constant K6 - for T T"	0.0/°F	0.0/°F
Constant K6 - for T > T"	0.0016/°F	0.00150/°F
T_{hot} Filter Constant*	N/A*	4 Seconds
[* Note: There is a 4 second T filter]		

Table 2.4.1-4
Steam Dump Control System (Load Rejection Controller)

Parameter	Current	SPU
Load Rejection Controller		
Deadband (TC-500A)	2°F	2°F
Modulate Open Setpoints	Bank 1 – 2.0 to 6.6°F Bank 2 – 6.6 to 11.2°F Bank 3 – 11.2 to 15.8°F	Bank 1 – 2.0 to 5.3°F Bank 2 – 5.3 to 8.6°F Bank 3 – 8.6 to 12.0°F
Trip Open Setpoints Hi 1(T_{avg} – T_{ref}) TB-500B Hi 2(T_{avg} – T_{ref}) TB-500C	 6.6°F 15.8°F	 5.3°F 12.0°F/7.0°F*
Proportional Gain (TC-500A)	9.3%/°F	10.0%/°F
[*Note: MPS3 has two options for conducting T_{avg} coastdown. Option 1 - the Hi 2 setpoint remains at 12.0°F. Option 2 (alternate coastdown) the Hi 2 setpoint is changed to 7.0°F. The Hi 2 setpoint must be reset to 12.0°F prior to subsequent startup for the new fuel cycle. Refer to Section 2.4.2, Plant Operability]		

2.4.2 Plant Operability

2.4.2.1 Regulatory Evaluation

NSSS I&C systems are required to respond to the initiation of plant operational transients without initiating a reactor trip or ESF actuation signal. NRC review standard RS-001 does not explicitly reference the SRP or other guidance documentation for license basis reviews regarding plant operability. DNC conducted an evaluation of the NSSS I&C systems response to operational transients at SPU conditions to ensure that the responses remain acceptable.

The acceptance criteria are based on:

- GDC-13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the RCPB, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

MPS3 Current Licensing Basis

As noted in FSAR Section 3.1, the MPS3 design bases are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A as amended through October 27, 1978. The adequacy of the MPS3 I&C systems design relative to the GDC is discussed in the FSAR Sections 3.1.1 and 3.1.2, and Section 2.4.1.

Specifically, the adequacy of the MPS3 design regarding conformance to:

- GDC-13 is described in FSAR Section 3.1.2.13, Instrumentation and Control (Criterion 13)

  Instrumentation and controls are provided to monitor and control neutron flux, control rod position, temperatures, pressures, flows and levels as necessary to assure that adequate plant safety can be maintained. Instrumentation is provided in the reactor coolant system, steam and power conversion system, the containment, engineered safety features systems, and other auxiliaries. Parameters that must be provided for operator use under normal operating and accident conditions are indicated in proximity with the controls for maintaining the indicated parameter in the proper range.

  The quantity and types of processing instrumentation provided ensures safe and orderly operation of all systems over the full design range of the plant. These systems are described in FSAR Chapters 6, 7, 8, 9, 11, and 12.

FSAR Section 7.7 defines the general design objectives of the plant control systems as:

- Establishing and maintaining power equilibrium between primary and secondary systems during steady state operation
- Constraining operational transients so as to preclude unit trip and re-establish steady state unit operation

- Providing the reactor operator with monitoring instrumentation that indicates all required input and output control parameters of the systems, and provides the operator the capability of assuming manual system control

  FSAR Section 7.7.1 describes the plant control systems. It addresses the Reactor Control System, Rod Control System, Systems for Monitoring and Indicating, Plant Control System Interlocks, Pressurizer Pressure Control, Pressurizer Water Level Control, SG Water Level Control, Steam Dump Control, and Incore Instrumentation.

The following FSAR sections define the current operational transients that MPS3 must be able to sustain without initiating a reactor trip or an ESF actuation signal.

7.7.2.3 Step Load Change Without Steam Dump

The plant control system restores equilibrium conditions, without a trip, following a +/-10 percent step change in load demand over the 15-100 percent power range for automatic control. Steam dump is blocked for load decreases less than or equal to 10 percent.

7.7.2.4 Loading and Unloading

Ramp loading and unloading of 5 percent per minute can be accepted over the 15 to 100 percent power range under automatic control without tripping the plant.

7.7.2.5 Load Rejection Furnished by Steam Dump

When a load rejection occurs, if the difference between the temperature setpoint of the RCS and the actual temperature exceeds a predetermined amount, a signal will actuate the steam dump to maintain RCS temperature within the control range until a new equilibrium is reached. The reactor power is reduced at a rate consistent with the capability of the rod control system (10 percent). The steam dump flow capacity is 40 percent of full steam flow. Thus, the turbine generator can take a step load reduction of up to 50 percent without a reactor trip or turbine trip.

7.7.2.6 Turbine Generator Trip without Reactor Trip

Whenever the turbine generator trips at an operating power level above the P-9 setpoint, the reactor also trips. A turbine generator trip below P-9 will not result in a reactor trip. The steam dump system is controlled from the RCS T_{avg}, signal whose setpoint values are programmed as a function of turbine load. Actuation of the steam dump is rapid to prevent actuation of the steam generator safety valves."

The I&C systems and components were evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005 defines the scope of the license renewal. NUREG-1838 Sections 2.5 and 3.6 are applicable to I&C systems and components. However, specific operational transient analysis is not within the scope of license renewal.

2.4.2.2 Technical Evaluation

2.4.2.2.1 Introduction

The operational transients were analyzed using the proposed NSSS control system settings and setpoints to demonstrate adequate margin exists to relevant reactor trip and ESF actuation setpoints over the SPU full power T_{avg} normal operating range of 581.5°F to 589.5°F. The SPU operating conditions are shown in Section 1.1, Nuclear Steam Supply System Parameters.

Additional analyses were performed to address the full power T_{avg} temperature coastdown maneuver. The T_{avg} coastdown maneuver is a very slow cooldown (typically 1°F to 2°F drop per day) of the entire NSSS at the end of a fuel cycle to maximize fuel burnup. Additional analyses were performed to address the full power T_{avg} temperature coastdown to 571.5°F. MPS3 has two options for conducting the T_{avg} coastdown.

Option 1 (Coastdown)

This T_{avg} coastdown maneuver is shown in Figure 2.4.2-1. The maneuver starts with the plant at hot full power, all rods out or near out, and the RCS boron concentration at or near zero. The coastdown begins with a T_{avg} decrease from 589.5°F to valves wide open (VWO) or 571.5°F at a slow rate. Then a power reduction begins while T_{avg} is maintained relatively constant until T_{avg} intersects the full power programmed temperature curve. Depending on the full power operating temperature (between 581.5°F and 589.5°F) prior to the coastdown, the plant will return to the programmed reference temperature between approximately 45 percent and 59 percent power. A simultaneous reduction in temperature and power continues to no-load conditions. The steam dump load rejection controller Hi 2 trip open setpoint remains at the normal operation value of 12.0°F for this option. (Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems, Table 2.4.1-4)

Option 2 (Alternate Coastdown)

This coastdown maneuver is shown in Figure 2.4.2-2. The maneuver starts with the plant at hot full power, all rods out or near out, and the RCS boron concentration at or near zero. The coastdown begins with a T_{avg} decrease from 589.5°F to VWO or 571.5°F at a slow rate. Then a simultaneous reduction in temperature and power begins to no-load conditions. In order to obtain acceptable results, the steam dump load rejection controller Hi 2 trip open setpoint must be changed from 12.0°F to 7.0°F prior to the start of the coastdown maneuver, and reset back to 12.0°F prior to the subsequent startup for the new fuel cycle. (Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems, Table 2.4.1-4)

For the SPU analysis, the definition of the load rejection transient was revised from a step change to a ramp load change at a maximum rate of 200 percent per minute. This change in the definition from a step change to a ramp load change at a maximum rate of 200 percent per minute redefines the load rejection in a more realistic manner and is consistent with uprating projects previously performed on other Westinghouse plants. The following operational transients were addressed for the SPU:

- 5 percent/minute Unit Loading and Unloading
- 10 percent Step Load Increase

- 10 percent Step Load Decrease
- 50 percent Load Rejection (i.e 50 percent loss of net load at 200 percent/minute)
- Turbine Trip without Reactor Trip from the P-9 Setpoint

The 5 percent per minute loading and unloading transients are not limiting transients for this evaluation and are enveloped by the other analyzed transients; therefore no specific analysis was performed for the 5 percent per minute loading and unloading transients.

The limiting transients with respect to the end-of-cycle (EOC) T_{avg} coastdown maneuver are the turbine trip without reactor trip and the 50 percent load rejection transients.

2.4.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The following inputs are applicable for the transients analyzed:

- All applicable NSSS control systems were assumed to be functioning as-designed and operating in the automatic mode of control. As part of the SPU project the automatic rod withdrawal feature is being disabled. To address the T_{avg} coastdown maneuver, the limiting transients were analyzed with the rods in manual control.
- The pressurizer pressure and steam dump control systems were credited in the analyses. The steam generator and pressurizer level control systems were not explicitly modeled and not specifically addressed for the SPU conditions in this analysis.
- In accordance with the Westinghouse methodology, 2 percent conservatism was applied to the initial power level in the analysis. The other plant parameters (RCS T_{avg}, pressurizer pressure, pressurizer level, steam generator mass at the nominal water level) were assumed to be at the nominal full power values.
- Best-estimate reactor kinetics parameters were modeled (rod worth, moderator temperature coefficient (MTC), doppler power defect, etc.) for the normal operating transient conditions. Since beginning-of-cycle (BOC) core physics parameters have lower differential rod worth and a less negative MTC, modeling BOC core characteristics yield more conservative results that bound the full cycle of operation. To address the T_{avg} coastdown maneuver, the limiting transients were analyzed at EOC fuel reactivity conditions.
- The initial conditions for each of the transients were chosen to maximize the transient responses.
- The analysis used current (as-installed) steam dump valve capacities at the SPU conditions.

The analyses assumed reactor protection and control system settings initially derived from the SPU accident and transient analyses discussed in Section 2.8.5, Accident and Transient Analyses. Furthermore, the analyses included the setpoint changes and plant modifications listed below and described in detail in Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems. The following is a summary of the setpoint changes and plant modifications considered in the analysis.

- Revised overtemperature and overpower ΔT reactor trip setpoints.

- Revised pressurizer level program limits.
- Revised steam dump control system setpoints for the load rejection controller.
- Implementation of a permissive to allow cold leg injection to occur automatically when both the safety inspection signal and a low RCS pressure permissive signal are present.
- Installation of a filter for the RTD T_{hot} input signal prior to input to the T_{avg} and ΔT module.
- Elimination of the automatic rod withdrawal feature.

The acceptance criterion for the analyses is that the operational transients should not result in a reactor trip or an engineered safety features actuation.

2.4.2.2.3 Description of Analyses and Evaluations

The analyses were performed using the multi-loop version of the Westinghouse LOFTRAN computer code. This computer model simulates the overall thermal-hydraulic and nuclear response of the NSSS as well as various control and protection systems. A LOFTRAN computer model was developed for MPS3 at the SPU conditions. The LOFTRAN code has been used to predict the plant responses for other SPU project. This methodology has been reviewed and approved by the NRC (Reference 1).

2.4.2.2.3.1 10 Percent Step Load Decrease

The 10 percent step load decrease transient was analyzed as a step decrease in turbine load from 100 percent to 90 percent power with 100 percent power corresponding to 3666 MWt NSSS power.

The analysis was performed at high T_{avg} (589.5°F) and 0 percent SGTP conditions to maximize the pressurizer insurge and pressure responses. In addition to not actuating a reactor trip or an engineered safeguards feature, the pressurizer pressure for a 10 percent step load decrease transient should not exceed the power operated relief valve (PORV) setpoint, 2350 psia.

2.4.2.2.3.2 10 Percent Step Load Increase

The 10 percent step load increase transient was analyzed as a step increase in turbine load from 90 percent to 100 percent power with 100 percent power corresponding to 3666 MWt NSSS power.

The analysis was performed at the lower analysis limit for T_{avg} (581.5°F) and 10 percent SGTP conditions to maximize the pressurizer outsurge. The limiting setpoints for this transient are the engineered safety features low steam line pressure of 658.6 psig (673.3 psia) and the reactor trip low pressurizer pressure of 1900 psia.

2.4.2.2.3.3 50 Percent Load Rejection

The 50 percent load rejection transient was analyzed as a rapid change in turbine load from 100 percent to 50 percent of the nominal power level at a maximum 200 percent per minute turbine runback rate. Redefining the 50 percent load rejection transient as a rapid ramp load decrease at a maximum turbine runback rate of 200 percent per minute is consistent with uprating projects previously performed on other Westinghouse plants. This transient is the most severe operational transient that the plant would normally experience.

The steam dump system was credited for this analysis using the revised steam dump setpoints for the SPU as documented in Section 2.4.1. The analysis was performed with two steam dump valves out-of-service. The analysis was performed at the lower normal operating temperature limit for T_{avg} (581.5°F) because it provides the lowest operating steam pressure condition and the lower steam dump capacity. These conditions would result in a larger initial NSSS heatup and lowest margin to reaching a reactor trip setpoint.

The limiting setpoints for this transient are the engineered safety features low steam line pressure of 658.6 psig (673.3 psia) and the reactor trip low pressurizer pressure of 1900 psia.

The 50 percent load rejection transient was also analyzed to address the EOC full power T_{avg} temperature coastdown maneuver to 571.5°F with two steam dump valves out-of-service.

2.4.2.2.3.4 Turbine Trip without Reactor Trip

After the Three Mile Island (TMI) incident, the NRC had expressed a concern on the implementation of any plant features that could increase the probability of a stuck-open pressurizer PORV. The NRC position is addressed in NUREG-0737, Item II.K.3.10 (Reference 2).

To address the NRC position, this analysis was performed to demonstrate that the pressurizer PORVs setpoint (2350 psia) is not challenged following a turbine trip without a reactor trip at or below the P-9 setpoint (51 percent power). In addition, the analysis was performed to demonstrate the transient would not result in a reactor trip or engineered safeguards feature actuation. The transient was analyzed as a step decrease in turbine load from 51 percent to 0 percent power.

The analysis was performed at high T_{avg} (589.5°F) and at the lower normal operating temperature limit for T_{avg} (581.5°F). The steam dump system was credited using the revised steam dump setpoints, and the analysis was performed with two steam dump valves out-of-service.

The transient was also analyzed to address the EOC full power T_{avg} temperature coastdown maneuver to 571.5°F with two steam dump valves out-of-service.

2.4.2.2.3.5 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for the nuclear design of these control systems. The NSSS instrumentation and control system components are treated for license renewal purposes as a commodity group discussed in NUREG-1838, Section 2.5, Electrical and Instrumentation and Controls Systems. The aging management programs applicable to this commodity group are discussed in Section 3.6, Electrical and Instrumentation and Controls. There is no impact on the aging management evaluations and they remain valid for the SPU conditions. The operational transient analysis was not within the scope of license renewal.

2.4.2.2.4 Results

These analyses concluded that the changes to the reactor protection and reactor controls identified in Section 2.4.1 and summarized in Section 2.4.2.2.2, enable the plant to continue to satisfy the requirements for operational transients, as described below.

2.4.2.2.4.1 5 Percent/Minute Loading and Unloading

Acceptable results were obtained for the 10 percent step load increase and decrease, 50 percent load rejection, and turbine trip without reactor trip transients, which envelop the 5 percent per minute loading and unloading transients. Therefore, the response to a 5 percent per minute unit loading and unloading transients at the SPU conditions is acceptable.

2.4.2.2.4.2 10 Percent Step Load Decrease

The analysis demonstrated the pressurizer pressure remained below the PORV setpoint of 2350 psia and the control system response was smooth during the transient with no excessive oscillatory responses noted. Therefore, the response to a 10 percent step load decrease transient at the SPU conditions is acceptable.

2.4.2.2.4.3 10 Percent Step Load Increase

The analysis demonstrated the pressurizer pressure remained above the low pressurizer pressure reactor trip setpoint of 1900 psia, and the main steam pressure remained above the low steam line pressure safety injection actuation setpoint of 658.6 psig (673.3 psia). The pressurizer level remained above the low-low heater cutoff and letdown isolation setpoint of 22 percent. The control systems response was smooth during the transient with no excessive oscillatory responses. Therefore, the response to a 10 percent step load increase transient at the SPU conditions is acceptable.

2.4.2.2.4.4 Turbine Trip without Reactor Trip

The results of the analysis demonstrated the peak pressurizer pressure remained below the PORVs setpoint of 2350 psia with two steam dump valves failed. The control system responses were stable with no excessive oscillatory responses noted. In order to maintain the peak pressure below the PORVs setpoint, the steam dump load rejection controller setpoints were modified. The revised load rejection controller setpoints are documented in Section 2.4.1.

For the T_{avg} coastdown, the analysis results are acceptable with the revised steam dump setpoints and two failed steam dump valves.

The turbine trip without reactor trip transient from the P-9 setpoint satisfies the criteria of the NUREG-0737, Item II.K.3.10 and is acceptable for the SPU conditions.

2.4.2.2.4.5 50 Percent Load Rejection

The results of the 50 percent load rejection transient analysis with the revised steam dump setpoints demonstrated that no reactor trip or engineered safety features were challenged. The analysis was performed with two steam dump valves failed. The control systems response was smooth during the transient with no excessive oscillatory responses.

For the T_{avg} coastdown, the 50 percent load rejection analysis results are acceptable with the revised steam dump setpoints and two failed steam dump valves. No reactor trip or engineered safety features were challenged.

Therefore the plant response to a 50 percent load rejection at the SPU conditions is acceptable.

2.4.2.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the plant response to operational transients. DNC concludes that the evaluations have adequately accounted for the effects of the proposed SPU on the plant operational capability, that the changes necessary to achieve satisfactory results at SPU are consistent with the plant's design basis, and will meet the current licensing basis with respect to the requirements of GDC-13. Therefore, DNC finds the proposed SPU acceptable with respect to plant operability.

2.4.2.4 References

1. WCAP-7907-A, LOFTRAN Code Description, April 1984.
2. NUREG-0737, “Clarification of TMI Action Plan Requirements,” Item II.K.3.10, Proposed Anticipatory Trip Modification, October 1980.

Figure 2.4.2-1

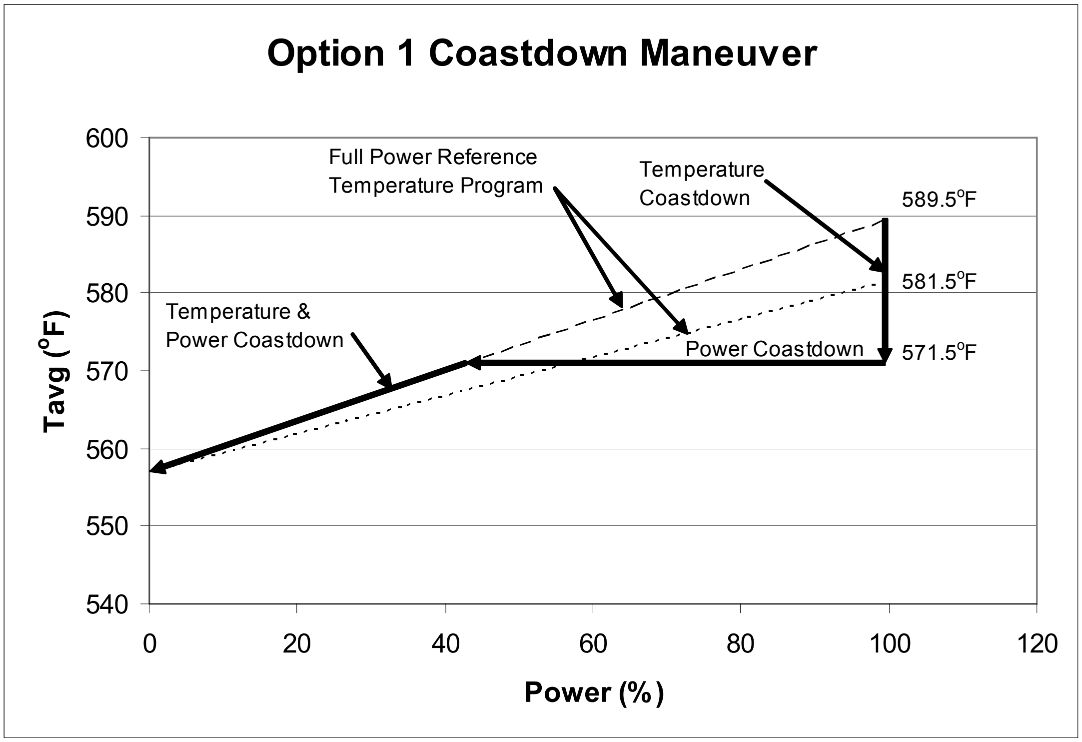
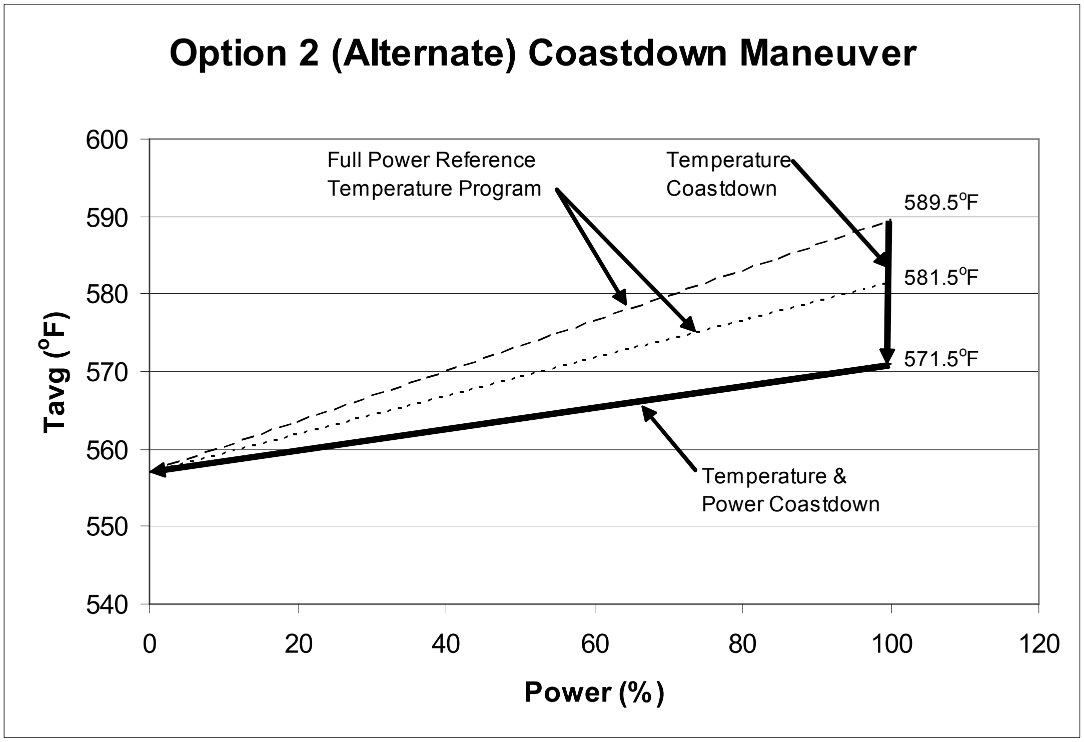

Option 1 Coastdown Maneuver
Full Power Reference Temperature Program
Temperature Coastdown
589.5°F
581.5°F
571.5°F
Temperature & Power Coastdown
Power Coastdown
Tavg (°F)
Power (%)
600
590
580
570
560
550
540
0
20
40
60
80
100
120

Figure 2.4.2-2


Option 2 (Alternate) Coastdown Maneuver
Full Power Reference Temperature Program
Temperature Coastdown
589.5°F
581.5°F
571.5°F
Temperature & Power Coastdown
Tavg (°F)
600
590
580
570
560
550
540
0
20
40
60
80
100
120
Power (%)

2.4.3 Pressurizer Component Sizing

2.4.3.1 Regulatory Evaluation

The pressurizer pressure control system (consisting of the pressurizer heaters, spray, and power-operated relief valves (PORV)) provides the means of controlling pressure to less than the RCS design basis value during steady state operations, and minimizes pressurizer pressure excursions during design basis operational transients. NRC review standard RS-001, Rev. 0 does not explicitly call out SRPs or other guidance documentation for either current or post-uprate license basis reviews for pressurizer component sizing. DNC conducted a review of the pressurizer pressure control system responses to meet design basis operational functions at SPU conditions to ensure the system responses continue to meet their design basis operational functions.

The acceptance criteria are based on 10 CFR 50.55a (a)(1); 10 CFR 50.55a(h); and:

- GDC-1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, constructed, and tested to quality standards commensurate with the importance of the safety functions to be performed.
- GDC-13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to ensure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the RCPB, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.
- GDC-19, insofar as it requires that a control room be provided from which actions can be taken to operate the nuclear unit safely under normal conditions, and maintain it in a safe condition under accident conditions, including LOCAs.
- GDC-24, insofar as it requires that the protection systems be separated from the control systems to the extent that a system satisfying all reliability, redundancy and independence requirements of the protection systems is left intact in the event of a failure of any single control system component or channel, or failure or removal from service of any single control system component or channel that is common to the control and protection systems. Protection and control system interconnection will be limited to ensure that safety is not significantly impaired.

MPS3 Current Licensing Basis

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the GDC is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 pressurizer component sizing regarding conformance to:

- 10 CFR 50.55a is described in FSAR Section 5.2.1.1, Compliance with 10 CFR Part 50.55a, and FSAR Table 5.2-1, Applicable Code Addenda for Class 1 RCS Components.

- 10 CFR 50.55a(h) conformance is attained by meeting the plant's original license basis regarding compliance with IEEE 279-1971.
- GDC-1, Quality Standards and Records, is described in the FSAR Section 3.1.2.1.

  SSCs important to safety are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Quality standards applicable to safety related SSCs are generally contained in codes such as the ASME B&PV Code. The applicability of these codes is specifically identified throughout the FSAR and is summarized in FSAR Section 3.2.5.

  FSAR Chapter 17 provides direct reference to the Quality Assurance Program established to provide assurance that safety related SSCs satisfactorily perform their intended safety functions. The procedures for generating and maintaining appropriate design, fabrication, erection, and testing records are contained within the referenced documents.
- GDC-13, Instrumentation and Control, is described in FSAR Section 3.1.2.13.

  Instrumentation and controls are provided to monitor and control neutron flux, control rod position, temperatures, pressures, flows and levels as necessary to assure that adequate plant safety can be maintained. Instrumentation is provided in the reactor coolant system, steam and power conversion system, the containment, engineered safety features systems, and other auxiliaries. Parameters that must be provided for operator use under normal operating and accident conditions are indicated in proximity with the controls for maintaining the indicated parameter in the proper range.

  The quantity and types of processing instrumentation provided ensures safe and orderly operation of all systems over the full design range of the plant. These systems are described in FSAR Chapters 6, 7, 8, 9, 11 and 12.
- GDC-19, Control Room, is described in FSAR Section 3.1.2.19.

  The control room provided is equipped to operate the unit safely under normal and accident conditions. Its shielding and ventilation design permits continuous occupancy of the control room for the duration of a DBA without the dose to personnel exceeding 5 rem whole body. Based on 10 CFR 50.67, the applicable dose criterion was modified to 5 rem TEDE

  The auxiliary shutdown panel located in the west switchgear room has equipment, controls and instrumentation to accomplish, in conjunction with controls and indication located on the adjacent 460V emergency switchgear, a prompt hot shutdown and a safety grade cold shutdown. The panel is physically located outside of the control room. Thus, the uninhabitability of the control room would have no effect on the availability of the auxiliary shutdown panel and adjacent controls (FSAR Section 7.4.1.3).
- GDC-24, Separation of Protection and Control Systems, is described in FSAR Section 3.1.2.24.

  The protection system is separate and distinct from the control systems. Control systems may be dependent on the protection system in that control signals are derived from protection system measurements, where applicable. These signals are transferred to the control system by isolation devices which are classified as protection components. The adequacy of system isolation is verified by testing under conditions of postulated credible faults. The failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems, leaves intact a system which satisfies the requirements of the protection system. Distinction between channel and train is made in this discussion. The removal of a train from service is allowed only during testing of the train. FSAR Chapter 7 gives further details.

Other FSAR sections which address the design features and functions of the pressurizer pressure control related systems or their control include Sections 5.2.2.11, 5.4.10, 5.4.13 and 7.7.1.5.

Section 2.2.2.7 addresses the evaluation of the pressurizer and supports as pressure retaining components. Section 2.5.2 addresses the Pressurizer Relief Tank. Section 2.8.4.2 evaluates over pressure protection at power. Section 2.8.4.3 addresses overpressure protection during low temperature operation.

RCS components, including the pressurizer, were evaluated for continued acceptability to support license renewal. NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3," dated August 1, 2005, documents the results of that review in Sections 2.3B.1.3 and 3.1B.

2.4.3.2 Technical Evaluation

2.4.3.2.1 Introduction

As part of the SPU, the following pressurizer components were analyzed to ensure that the NSSS pressure control system is adequate for the increased transient pressures and temperatures for the SPU conditions shown in Section 1.1, Nuclear Steam Supply System Parameters." The analysis was performed to envelope the window of operating conditions, full power T_{avg} of 571.5°F to 589.5°F.

- Pressurizer power-operated relief valves (PORVs)
- Pressurizer spray valves
- Pressurizer heaters

The pressurizer pressure control system components are described in the MPS3 SPU FSAR Sections 5.4.10, 5.4.13, and 7.7.1.5.

To support the MPS3 SPU, several setpoint changes and plant modifications are made and are described in detail in Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems. The changes include a new pressurizer level program, a change to the control system logic for a safety injection signal interlock for both the safety injection signal and low RCS pressure signal, the addition of an RTD T_{hot} filter, revised steam dump load rejection controller settings, elimination of automatic rod withdrawal, and OPΔT and OTΔT setpoint changes. This analysis includes these changes.

2.4.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

2.4.3.2.2.1 Pressurizer PORVs

The pressurizer PORV sizing analysis was performed at the MPS3 SPU operating conditions shown in Section 1.1, Nuclear Steam Supply System Parameters. With the NSSS power SPU of 3666 MWt (3650 MWt reactor power), the demand on the pressurizer PORVs increases. Therefore, the pressurizer PORV sizing analysis was performed to ensure acceptability. The analysis was performed following the general guidelines and methodology presently in use. This included the following key input parameters and assumptions listed below:

- The transient is conservatively modeled as a 50 percent step load reduction from 100 percent to 50 percent power with 100 percent power corresponding to 3666 MWt NSSS power.
- A maximum steam pressure condition provides the maximum pressurizer insurge, therefore, a 0 percent steam generator tube plugging (SGTP) level is used in the analysis.
- The plant is initially at nominal full power T_{avg} plus a 4.0°F uncertainty. The analysis was performed at the lower analysis limit for T_{avg} (571.5°F) conditions and at the high T_{avg} (589.5°F) conditions.
- The initial pressurizer pressure is at nominal pressure of 2250 psia.
- The initial pressurizer water level is at the nominal setpoint applicable to the full power T_{avg} operating conditions. The pressurizer level program limits were revised for the SPU and were used in this analysis.
- The pressurizer PORV installed capacity is 210,000 lbm/hour saturated steam per valve at 2350 psia. There are a total of two pressurizer PORV valves.
- The NSSS control systems for rod control (automatic insertion only), steam dump control, pressurizer pressure and level control systems are assumed functioning as designed and are in the automatic mode of control. The automatic rod withdrawal feature is disabled.
- Best-estimate nuclear design parameters (moderator temperature coefficient, doppler power defect, control rod worth, and startup data) at conservative beginning-of-life (BOL) conditions were assumed.

At SPU conditions the pressurizer PORVs sizing basis is each valve capacity should be sufficient to limit the pressurizer pressure to below the high pressurizer pressure reactor trip setpoint of 2385 psia for the design basis large step-load decrease with steam dump transient. This design basis load rejection is defined as a 50 percent step-load decrease from 100 percent to 50 percent power.

2.4.3.2.2.2 Pressurizer Spray Valves

The pressurizer spray valve sizing analysis was performed at the MPS3 SPU operating conditions discussed in Section 1.1, Nuclear Steam Supply System Parameters. With the uprating, the demand on the pressurizer spray valves increases. Therefore, the pressurizer spray sizing analysis was performed to ensure acceptability at the SPU conditions. The analysis was performed following the general guidelines and methodology presently in use. This included the following key input parameters and assumptions listed below:

- The transient is conservatively modeled as a 10 percent step-load reduction from 100 percent to 90 percent power.
- The plant is initially at nominal high T_{avg} (589.5°F) plus a 4.0°F uncertainty. A 0 percent SGTP level is used for the analysis.
- The initial pressurizer pressure is at nominal pressure of 2250 psia.
- The initial pressurizer water level is at the nominal setpoint applicable for the high T_{avg} operating conditions. The pressurizer level program limits were revised for the SPU and were used in this analysis.
- The installed pressurizer spray valve capacity is 450 gpm per valve. There are two valves for a total spray capacity of 900 gpm.
- The NSSS control systems for rod control (automatic insertion only), steam dump control, pressurizer pressure and level control systems are assumed functioning as designed and are in the automatic mode of control. The automatic rod withdrawal feature is disabled. The steam dump system is not actuated for a 10 percent step-load decrease transient; therefore, steam dump system is not credited for this analysis.
- Best-estimate nuclear design parameters (moderator temperature coefficient, doppler power defect, control rod worth, and startup data) at conservative BOL conditions are assumed.

The acceptance criterion is that the total installed capacity (900 gpm total) of the pressurizer spray valves should be adequate to limit the peak pressurizer pressure to less than the pressurizer PORV actuation setpoint of 2350 psia for a 10 percent step load decrease transient. For load decreases up to 10 percent power, the spray valves are the primary means of controlling pressure without actuating the pressurizer PORVs when in automatic pressure control mode.

2.4.3.2.2.3 Pressurizer Heaters

The pressurizer heaters are sized to be able to heat up the pressurizer liquid at a maximum rate of a 100°F per hour during the initial plant heatup phase from cold shutdown. In addition, the heaters assist the plant in controlling the pressurizer pressure decrease that would occur during design basis transients that result in pressurizer outsurge events. The heater capacity should be sufficient to maintain the pressurizer pressure above the low pressurizer pressure reactor trip setpoint of 1900 psia during the 50 percent load rejection and 10 percent step load increase transients which are limiting for challenges to the low pressurizer pressure reactor trip setpoint. The design basis pressurizer heater capacity is 1 kW/ft^3 of heater capacity per cubic foot of pressurizer volume.

2.4.3.2.3 Description of Analyses and Evaluations

The PORV and spray sizing analyses were performed using the LOFTRAN computer code. This computer code simulated the overall thermal/hydraulic and nuclear response of the NSSS system as well as the control and protection systems. A plant specific LOFTRAN computer model was developed for the MPS3, 4-loop plant. The LOFTRAN code has been used to predict the plant responses for other SPU programs, and this methodology has been reviewed and approved by the NRC (Reference 1).

2.4.3.2.3.1 Pressurizer PORVs

A 50 percent step-load decrease transient from 100 percent power (with steam dumps) was analyzed using the configured version of the LOFTRAN computer code. The initial conditions for the transient are described in Section 2.4.3.2.2.1.

2.4.3.2.3.2 Pressurizer Spray Valves

A 10 percent step-load decrease transient from 100 percent power was analyzed using the configured version of the LOFTRAN computer code. The initial conditions for the transient are described in Section 2.4.3.2.2.2.

2.4.3.2.3.3 Pressurizer Heaters

The originally installed heater capacity was 1800 kW, 416 kW from the proportional heaters plus 1384 kW from the backup heaters. The pressurizer internal volume is 1800 ft^3, therefore, the sizing basis of 1 kW/ft^3 was met (1800 kW/1800 ft^3 = 1 kW/ft^3). The actual heater capacity is 1730 kW. The actual heater capacity is still acceptably close to the design basis sizing requirement of 1 kW/ft^3 and has shown at the current conditions to be sufficient to maintain the pressurizer pressure at its setpoint during steady-state operation and to minimize pressure excursions during design basis operational transients. In addition, based on the 10 percent step load increase and 50 percent load rejection transients addressed in Section 2.4.2, Plant Operability, it has been demonstrated that the actual heater capacity is acceptable because the low pressurizer pressure reactor trip setpoint (1900 psia) is not actuated.

The required heater capacity was not affected by the SPU conditions. Design basis transients resulting in pressurizer insurges/outsurges such as loadings/unloadings, load rejections, and reactor trips showed pressurizer pressure changes were too rapid for the pressurizer heaters to influence the pressure transient. Generic analyses (as well as plant operating experience) on Westinghouse plants have shown that the pressurizer heater capacity is not a strong influence on the minimum pressure noted during the above operational events, or during reactor trips. The minimum pressure is controlled by the outsurge that results during the transient. In addition, analyses done on other plants have shown very little difference in the maximum/minimum pressurizer pressure when it was assumed that a certain percentage of the pressurizer heaters were out of service. The heatup time from cold shutdown to hot standby is not affected by the SPU.

2.4.3.2.3.4 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 License Renewal Application for pressurizer pressure component sizing. The adequacy of the Pressurizer for license renewal is documented in the License Renewal SER, NUREG-1838, Sections 2.3B.1.3 and 3.1B. SPU activities are not adding any new components within the existing license renewal scoping evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Also, SPU activities do not add any new or previously unevaluated materials to the pressurizer. The evaluations performed for aging management remain valid for the SPU conditions.

2.4.3.2.4 Results

2.4.3.2.4.1 Pressurizer PORVs

The PORVs opened for this transient and the relief capacity was sufficient to limit the peak pressurizer pressure to less than the high pressurizer pressure reactor trip setpoint of 2385 psia. The PORVs capacity is adequate to avoid actuation of a reactor trip on high pressurizer pressure following a 50 percent load rejection transient for the SPU conditions. In addition, the maximum pressurizer water level remained below the high pressurizer level reactor trip setpoint of 89 percent.

2.4.3.2.4.2 Pressurizer Spray Valves

The total installed spray valve capacity of 900 gpm is sufficient to limit the peak pressurizer pressure to less than the pressurizer PORV actuation setpoint of 2350 psia and avoid actuation of the PORVs during a 10 percent step-load decrease transient for the SPU conditions.

2.4.3.2.4.3 Pressurizer Heaters

The actual heater capacity remains sufficient to maintain the pressurizer pressure at its setpoint during steady state operation and to minimize pressure excursions during design basis operational transients, for SPU conditions. The plant operability analyses described in Section 2.4.2, Plant Operability, demonstrate that the pressurizer pressure is able to be maintained above the low pressurizer pressure reactor trip setpoint of 1900 psia during the 50 percent load rejection and 10 percent step load increase design basis operational transients.

2.4.3.3 Conclusion

DNC has evaluated the effects of the proposed SPU on the functional design of the NSSS pressurizer pressure control systems. DNC concludes that the evaluation adequately addresses the effects of the proposed SPU on these systems and that the other changes that are necessary to the reactor control systems to achieve the proposed SPU, are consistent with the pressurizer pressure control systems' design basis. DNC further concludes that the pressurizer pressure control systems continue to meet the MPS3 current licensing basis requirements with respect to 10 CFR 50.55a(a)(1) and 10 CFR 50.55(a)(h), and GDC-1, GDC-13, GDC-19, and GDC-24.

Therefore, DNC finds the proposed SPU acceptable with respect to the pressurizer pressure control systems.

2.4.3.4 References

1. WCAP-7907-A, LOFTRAN Code Description, April 1984.

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

2.5.1.1.1.1 Regulatory Evaluation

DNC conducted a review in the area of flood protection to ensure that safety-related structures, systems, and components are protected from flooding. The DNC review covered flooding of safety-related structures, systems, and components from internal sources, such as those caused by failures of tanks and vessels. The DNC review focused on increases of fluid volumes in tanks and vessels assumed in flooding analyses to assess the impact of any additional fluid on the flooding protection that is provided.

The acceptance criterion for flood protection is based on GDC-2.

Specific review criteria are contained in the SRP, Section 3.4.1, and other guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Section 3.4.1, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

It is noted that SRP 3.4.1 identifies acceptance criteria in addition to GDC-2 (e.g., RG 1.59). This acceptance criteria is applicable to external flooding; therefore it is not covered in this evaluation.

The adequacy of MPS3 design relative to conformance to:

- GDC-2 is described in FSAR Section 3.1.2.2, Design Bases for Protection Against Natural Phenomena (Criterion 2).

  Those features of plant facilities that are essential to the prevention of accidents that could affect the public health and safety or to the mitigation of accident consequences are designed to comply with the following:

  1. Quality standards that reflect the importance of the function to be performed. Approved design codes are used when appropriate to the nuclear application.

  2. Performance standards that enable the facility to withstand, without loss of the capability to protect the public, the additional forces imposed by the most severe earthquake, flooding condition, wind, ice, or other natural phenomena for the site, as well as credible

> combinations of the effects of normal and accident conditions with the effects of the natural phenomena.
>
> All piping, components, and supporting structures of the reactor and safety-related systems are designed to withstand a specified seismic disturbance, as well as credible combinations of effects of normal and accident conditions coincident with the effects of natural phenomena. Plant-design criteria specify that there is to be no loss of function of such equipment in the event of the safe shutdown earthquake (SSE) ground acceleration simultaneously acting in the horizontal and vertical directions. The dynamic response of Seismic Category I structures to ground acceleration, based on an envelope of characteristics of the site foundation soils and on the critical damping of the foundation and structures, is included in the design analysis.

NRC Generic Letter 87-02, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue, was addressed to all holders of operating licenses not reviewed to current licensing criteria on seismic qualification of equipment. Current licensing criteria, as applicable to this issue, were defined within NUREG-1211, Regulatory Analysis for Resolution of Unresolved Safety Issue (USI) A-46, Seismic Qualification of Equipment in Operating Plants, February 1987, Section 1, Plants Affected. This document identified the current requirements for qualification of equipment in licensing as being defined in RG 1.100, IEEE Standard 344-1975. The FSAR Section 3.10B.1 specifically states in “The earthquake requirements and qualification methods conform to those outlined in IEEE Standard 344-1975, IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations, (Section 1.8, RG 1.100) and are in agreement with the recommendations of Branch Technical Position ICSB 10.” Therefore, USI A-46 does not apply to MPS3. This conclusion was documented in a letter from G. D. Hicks (NNECO) to the NRC, dated July 21, 1997, and was accepted by a letter from P. F. McKee (NRC) to N. S. Carns (NNECO), dated September 4, 1997.

FSAR Table 1.9-1 states that the FSAR does not address Item III.3 of SRP 3.4.1, Revision 2, which discusses review of postulated failures of nonseismic Category I and non-tornado-protected tanks. FSAR Table 1.9-2 provides the following justification for the difference from the SRP:

> MPS3 does not have QA Category 1 tanks that are nonseismic. Postulated failure of non-tornado protected tanks has been considered during the review of moderate-energy lines as described in FSAR Section 3.6. Items in this category are located outside safety-related structures in areas that would preclude flooding of safety-related equipment.
>
> Safety-related equipment required for safe shutdown of the plant is located in cubicles, or on elevated platforms, which would preclude damage due to potential flooding resulting from the failure of the non-QA Category 1 tanks during a seismic event.

In addition to the evaluations described above, the MPS3 barriers and equipment used to mitigate internal floods were evaluated for continued acceptability for the purpose of plant license renewal. The results of that review are found in NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005.

Section 2.4B.2 of the License Renewal SER identifies the components in plant structures that are within the scope of license renewal, including flood barriers in these structures.

2.5.1.1.1.2 Technical Evaluation

2.5.1.1.1.2.1 Introduction

Protection from internal flooding outside Containment due to failure of non-seismic Category 1 tanks and vessels is addressed in the following sections:

- Internal flooding due to high-energy line breaks and moderate-energy line cracks outside the containment structure is addressed in Section 2.5.1.3, Pipe Failures.
- Submergence inside Containment is addressed in Section 2.3.1, Environmental Qualification of Electrical Equipment.
- Protection of safety-related equipment from flooding due to a CWS expansion joint failure is addressed in Section 2.5.1.1.3, Circulating Water System (CWS).
- Internal flooding via the equipment and floor drains systems is addressed in Section 2.5.1.1.2, Equipment and Floor Drains.

2.5.1.1.1.2.2 Acceptance Criteria

MPS3's licensing basis addresses design of systems and components important to safety to withstand the effects of natural phenomena (GDC-2). Review guidance in SRP Section 3.4.1, Rev. 2, addresses (1) determination if liquid-carrying systems could produce flooding, and an evaluation of measures taken to protect safety-related equipment, and (2) review of the effects of potential flooding of systems and components due to postulated failure of non-seismic Category 1 and non-tornado-protected tanks, vessels, and other process equipment.

2.5.1.1.1.2.3 Description of Analyses and Evaluations

As stated above, internal flooding due to high-energy line breaks and moderate-energy line cracks outside the Containment structure is addressed in Section 2.5.1.3, Pipe Failures.

The non-Seismic Category 1 tanks and vessels located in safety-related structures outside the Containment were reviewed to determine if any of these tanks and vessels required an increase in capacity due to the SPU. Reviews were also performed to determine (1) if any new non-seismic Category 1 tanks or vessels are required as a result of the SPU, (2) if the SPU affects the location of existing safety-related equipment required for safe shutdown of the plant, or (3) if any new safety-related equipment in safety-related structures is required due to the SPU.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As addressed in the License Renewal SER, Section 2.4B.2, barriers used to mitigate internal floods are evaluated within the structure that contains them. Since the SPU does not add any new structures/components used to resist the effects of flooding, it does not affect the evaluation of these structures in the SER. Aging management of these structures/components is addressed in Section 3.5B of the License Renewal SER.

2.5.1.1.1.2.4 Results

The SPU does not increase the size or the amount of fluid in any of the non-Seismic Category 1 tanks and vessels located in safety-related structures outside the Containment. The SPU does not require the addition of any new non-Seismic Category 1 tanks or vessels. The SPU does not affect the location of existing safety-related equipment required for safe shutdown of the plant, nor does it require the addition of any new safety-related equipment required for safe shutdown. However, if new safety-related equipment is required, it will be implemented in accordance with the plant design change process. This process will address protection of the affected safety-related equipment from internal flooding due to failure of non-Seismic Category I tanks or vessels. Accordingly, the SPU does not affect the current licensing basis related to internal flooding due to failure of non-Seismic Category 1 tanks and vessels.

2.5.1.1.1.3 Conclusion

DNC reviewed internal flooding from tanks and vessels outside Containment, which could potentially affect safety-related components, for impact of the proposed SPU. DNC concludes that safety-related structures, systems, and components will continue to be protected from flooding from these sources, and will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-2 following implementation of the proposed SPU. Therefore, DNC finds that the proposed SPU is acceptable with respect to protection of safety-related SSC from flooding due to failure of non-Seismic Category 1 tanks and vessels.

2.5.1.1.2 Equipment and Floor Drains

2.5.1.1.2.1 Regulatory Evaluation

The function of the equipment and floor drains system is to assure that waste liquids, valve and pump leakoffs, and tank drains are directed to the proper area for processing or disposal. The equipment and floor drains system is designed to handle the volume of leakage expected, and prevent a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment. DNC's review of the equipment and floor drains system included the collection and disposal of liquid effluents outside Containment. The review focused on any changes in fluid volumes or pump capacities that are necessary for the proposed SPU and that are not consistent with previous assumptions with respect to floor drainage considerations.

The acceptance criteria for the equipment and floor drains system are based on GDCs -2 and -4 insofar as they require the equipment and floor drains system to be designed to withstand the effects of earthquakes and to be compatible with the environmental conditions (flooding) associated with normal operation, maintenance, testing, and postulated accidents (pipe failures and tank ruptures).

Specific review criteria are contained in the SRP, Section 9.3.3, and other guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, Rev. 2, July 1981, SRP Section 9.3.3.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in the FSAR Section 3.1.1 and 3.1.2.

The adequacy of MPS3 design relative to conformance to

- GDC-2 is described in FSAR Section 3.1.2.2, Design Bases for Protection Against Natural Phenomena (Criterion 2).

  Those features of plant facilities that are essential to the prevention of accidents that could affect the public health and safety or to the mitigation of accident consequences are designed to conform with the following:

  1. Quality standards that reflect the importance of the function to be performed. Approved design codes are used when appropriate to the nuclear application.

  2. Performance standards that enable the facility to withstand, without loss of the capability to protect the public, the additional forces imposed by the most severe earthquake, flooding condition, wind, ice, or other natural phenomena for the site, and credible

combinations of the effects of normal and accident conditions with the effects of the natural phenomena.

All piping, components, and supporting structures of the reactor and safety-related systems are designed to withstand a specified seismic disturbance and credible combinations of effects of normal and accident conditions coincident with the effects of natural phenomena. Plant design criteria specify that there is to be no loss of function of such equipment in the event of the safe shutdown earthquake (SSE) ground acceleration acting in the horizontal and vertical directions simultaneously. The dynamic response of Seismic Category I structures to ground acceleration, based on an envelope of characteristics of the site foundation soils and on the critical damping of the foundation and structures, is included in the design analysis.

NRC Generic Letter 87-02, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue, was addressed to all holders of operating licenses not reviewed to current licensing criteria on seismic qualification of equipment. Current licensing criteria, as applicable to this issue, were defined within NUREG-1211, Regulatory Analysis for Resolution of Unresolved Safety Issue (USI) A-46, Seismic Qualification of Equipment in Operating Plants, February 1987, Section 1, Plants Affected. This document identified the current requirements for qualification of equipment in licensing as being defined in RG 1.100, IEEE Standard 344-1975. The FSAR Section 3.10B.1 states: “The earthquake requirements and qualification methods conform to those outlined in IEEE Standard 344-1975, ‘IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations,’ (Section 1.8, RG 1.100) and are in agreement with the recommendations of Branch Technical Position ICSB 10.” Therefore, USI A-46 does not apply to MPS3. This conclusion was documented in a letter from G. D. Hicks (NNECO) to NRC, dated July 21 ,1997, and was accepted by a letter from P. F. McKee (NRC) to N. S. Carns (NNECO), dated September 4, 1997.

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4).

Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including loss of coolant accidents (LOCA). These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

Structures, systems, and components important to safety are classified as QA Category 1 and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

As addressed in FSAR Section 9.3.3:

- The reactor plant vent and drains systems are non-safety-related, except for the lines penetrating the containment and three safety-related sumps located in the ESF Building. Two of the three sumps (3DAS* sump 7A & B) collect miscellaneous equipment drainage. The third sump is the porous concrete groundwater sump that collects groundwater that may have circumvented the waterproof membrane that surrounds the containment structure and buildings contiguous to the containment structure. For containment penetration areas, the isolation valves on both sides of the containment structure wall and the piping between them are Safety Class 2.
- The reactor plant vent and drain systems are designed and sized to handle the maximum flow rate of vents and drains expected during unit operation.
- The residual heat removal cubicle sumps and pumps are located in safety-related areas, although they are not safety-related themselves. The cubicles are completely separate from one another. Furthermore, drain piping is run to an elevation high enough to prevent back flooding from the ESF Building to these cubicles.

In addition to the evaluations described above, the MPS3 reactor plant aerated drains system was evaluated for continued acceptability for the purpose of plant license renewal. The results of that review are found in NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005. The reactor plant aerated drains system is evaluated in Sections 2.3B.3.51 and 3.3B.2.3.48 of the License Renewal SER.

2.5.1.1.2.2 Technical Evaluation

2.5.1.1.2.2.1 Introduction

This section addresses the impact of the SPU on safety-related components in the equipment and floor drains system, the sources and quantities of liquids that enter the equipment and floor drains system, crediting flow through floor drains in the building flooding analyses, and the potential for cross-cubicle/building flooding via the equipment and floor drains systems.

The impact of the SPU on potential flooding from water fire suppression systems is addressed in Section 2.5.1.4, Fire Protection.

The impact of the SPU on system design to protect against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drains system is addressed in Section 2.5.6.2, Liquid Waste Management Systems.

2.5.1.1.2.2.2 Acceptance Criteria

MPS3's licensing basis addresses design of systems and components important to safety to withstand the effects of natural phenomena (GDC-2). Guidance in SRP 9.3.3, Rev. 2, addresses safety-related portions of the system being capable of withstanding the effects of earthquakes, and inundation of safety-related areas due to drain backflow.

MPS3's licensing basis addresses design of systems to accommodate the effects of environmental conditions associated with normal operation, maintenance, testing, and postulated accidents (GDC-4). Guidance in SRP 9.3.3, Rev. 2, addresses system design to prevent flooding which could result in adverse affects on essential systems or components.

2.5.1.1.2.2.3 Description of Analyses and Evaluations

The safety-related components in the equipment and floor drains system were identified. These include the lines penetrating the Containment, the three safety-related sumps in the ESF Building, and the level instruments for monitoring water level in the following areas: pipe tunnel, ECCS pump cubicle, RHR pump cubicles, and RSS pump cubicles. Review was performed to determine if any of these components are impacted by the SPU or if any new safety-related components are required as a result of the SPU.

For plant structures containing equipment and floor drains, a review was performed to identify any new equipment or modification of existing equipment in these structures, due to the SPU, would result in increasing the quantities of liquids entering the equipment and floor drains system.

The impact of the SPU on the analysis of potential flooding in the Auxiliary Building due to a pipe crack, which considers flow through floor drains, was evaluated.

The impact of the SPU on the analysis of the potential for cross-cubicle/building flooding via the equipment and floor drains system was evaluated.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed in Section 2.5.1.1.2.1, the reactor plant aerated drains system is within the scope of plant license renewal. As addressed in the NRC's evaluation of this system, the NRC found that MPS3 had acceptable programs for managing the aging effects applicable to system components (e.g., loss of material of stainless steel pipe and valve component types exposed to atmosphere/weather). The SPU does not add any new materials to this equipment, does not affect the existing materials, and does not affect the environments to which these materials are exposed. Therefore, the SPU does not affect the evaluations/conclusions in the License Renewal SER regarding the reactor plant aerated drains system, and no new aging effects requiring management are identified.

2.5.1.1.2.2.4 Results

The SPU does not affect the existing safety-related components in the equipment and floor drains system and does not require adding any new safety-related components.

The SPU does not add any new equipment or modify existing equipment (e.g., pumps, strainers) in plant structures that would result in increasing the quantities of liquids currently entering the equipment and floor drains system. As addressed in Section 2.5.1.1.1.2.4, the SPU does not increase the size or the amount of fluid in any of the non-seismic Category 1 tanks and vessels located in safety-related structures. Therefore, there is no additional leakage from these sources that would affect the equipment and floor drains system.

The analysis of potential flooding in the Auxiliary Building states that flood water in the upper elevations of the building will flow to the lowest elevation of the building via drains and open stairwells, and it conservatively assumes that water flowing from a pipe break will end up at the lowest possible elevation. The limiting sources of flood water identified in the Auxiliary Building flooding analysis are moderate-energy pipe cracks in the SWS, RPCCW system and FPW system. These sources are all located at the lowest elevation in the building and envelope any sources flowing from upper elevations of the building. At SPU conditions there is no significant change in the operating flow rates or pressures of the SWS (Section 2.5.4.2) or the RPCCW system (Section 2.5.4.3). The SPU does not affect the operating flow rates or pressures of the FPW system. Also, the SPU does not affect the analysis methodology regarding flow of flood water from upper elevations of the building to the lowest elevation of the building via drains and open stairwells.

The analysis of the potential for cross-cubicle/building flooding via the equipment and floor drains system, that could impact safety-related equipment, addresses the following structures:

- ESF Building
- Auxiliary Building
- Emergency Generator Enclosure
- Fuel Building
- Service Building
- Control Building
- Service Water Cubicles

The cross cubicle/building flooding analysis refer to the flooding analyses associated with these structures, as discussed in Section 2.5.1.3, and assumes no blockage of drainage piping. A summary of the impact of the SPU on the cross-cubicle/building flooding analysis is as follows:

- The sources of flood water in the analysis are moderate-energy line cracks in an SWS line, RPCCW system line, an LPSI system line, or a FPW system line. At SPU conditions, there is no significant change in the operating flow rates or pressures of the SWS (Section 2.5.4.2), RPCCW system (Section 2.5.4.3), or the LPSI system (Section 2.2.4). The SPU does not affect the operating flow rates or pressures of the FPW system.
- Cross-cubicle flooding of each residual heat removal system cubicle in the ESF Building from adjacent cubicles via the residual heat removal cubicle sump pump discharge line is not possible, because the sump pump discharge line penetrates the boundary wall between the residual heat removal cubicle and the adjacent cubicles at an elevation well above the maximum flood level in the adjacent cubicles. The SPU does not affect the piping configuration of the equipment and floor drains systems in the ESF Building.

- The Hydrogen Recombiner Building equipment and floor drains are routed through the ESF Building. However, the equipment and floor drains systems in the buildings are separated by normally closed isolation valves. The SPU does not affect this valve lineup.
- The piping and valving arrangement in the Emergency Generator Enclosure precludes cross-cubicle flooding via the equipment and floor drains systems. The SPU does not affect this piping and valve arrangement.
- No cross building communication into the Control Building is possible due to the piping configuration. The SPU does not affect the piping configuration of the equipment and floor drains system in this building.
- As noted above, the Service Water cubicle flooding analysis is discussed in Section 2.5.1.3. This analysis states that there is no pathway between the redundant service water cubicles; flooding in one cubicle will not affect equipment in the redundant cubicle. No cross-cubicle communication via sump pump discharge piping is possible since each line discharges separately into separate service water cubicles. The SPU does not affect the piping configuration of the equipment and floor drains system in these cubicles.

The cross-cubicle/building flooding analysis concludes that cross-cubicle/building flooding via the equipment and floor drains system does not increase the severity of any internal flood, nor does it invalidate the conclusions of the individual structure flooding analyses. As addressed above, the SPU does not affect this conclusion.

2.5.1.1.2.3 Conclusion

DNC has reviewed the effects of the proposed SPU on the equipment and floor drains system. The SPU does not add any new equipment or modify existing equipment (e.g., pumps, strainers) in plant structures that would result in increasing the quantities of liquids currently entering the equipment and floor drains systems. DNC concludes that the equipment and floor drains systems has sufficient capacity to prevent the backflow of water to areas with safety-related equipment. Based on this, DNC concludes that the equipment and floor drains systems will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-2 and GDC-4 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the equipment and floor drains system.

2.5.1.1.3 Circulating Water System (CWS)

2.5.1.1.3.1 Regulatory Evaluation

The CWS provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems. The review of the CWS focused on changes in flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed SPU. MPS3's acceptance criteria for the CWS are based on GDC-4 for the effects of flooding of safety-related areas due to leakage from the CWS and the effects of malfunction or failure of a component or piping of the CWS on the functional performance capabilities of safety-related structures, systems, and components.

Specific review criteria are contained in the SRP, Section 10.4.5, and other guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, SRP Section 10.4.5, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 design relative to conformance to

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4), as follows:

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCA's. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

  Structures, systems, and components important to safety are classified as QA Category 1 and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

  FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

As addressed in NUREG-1031, MPS3 Safety Evaluation Report, August 2, 1984, Section 10.4.5, Circulating Water System, the CWS was reviewed in accordance with SRP Section 10.4.5.

As addressed in FSAR Section 10.4.5:

1. There are no essential systems or components required for safe shutdown or to mitigate the effects of an accident, located within the Turbine Building that could be affected by flooding due to a circulating water pipe or expansion joint rupture. In addition, there are no passageways, pipe chases, or cableways that could be rendered inoperable by flood waters generated by a complete rupture of a main condenser circulating water expansion joint. However, a pipe tunnel is provided at the basement floor, at Elevation 14 ft. 6 in., in the Turbine Building, connecting the Turbine Building to the safety-related Auxiliary Building. This tunnel is totally sealed with a fire barrier at the Auxiliary Building and will prevent any water from entering the Auxiliary Building. Note that this fire barrier is also a barrier for radiation, HELB, CO_2, water and SLCRS.

2. High water level in the condenser circulating water discharge pit sounds an alarm in the Control Room, enabling the operators to stop circulating water flow through the circulating water piping in 60 seconds; however, for design purposes, it is assumed that operator action is delayed for 15 minutes. Within 15 minutes the total amount of water spillage into the Turbine Building could be approximately 2,250,000 gallons. This water results in a water level at approximately Elevation 21 ft. 6 in. This level of water does not affect any essential systems or components.

FSAR Section 10.4.1 states that flooding due to a complete condenser failure will not damage any safety-related equipment inside or outside the Turbine Building. The worst case of flooding results from an expansion joint failure at the condenser inlet.

A circulating water expansion joint rupture in the Turbine Building could result in internal flooding until the water level reaches Elevation 28 ft. The sump alarm system that is provided to detect flooding in the Turbine Building is not safety-related. To compensate for this, the siding panel with pressure release feature is provided at Elevation 24 ft. 6 in. between column lines A39 and A43 of the Turbine Building. This siding panel will blow out if the floodwater reaches Elevation 28 ft inside the Turbine Building. This panel is located on the west side of the Turbine Building, away from several Category 1 structures which are located east of the Turbine Building. Therefore, continued operation of the circulating water pumps will not result in damage to safety-related systems or components.

In addition to the evaluations described above, the CWS was evaluated for continued acceptability for the purpose of plant license renewal. The results of that review are found in NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005. The CWS is evaluated in Sections 2.3B.3.1 and 3.3B.2.3.1 of the License Renewal SER.

2.5.1.1.3.2 Technical Evaluation

2.5.1.1.3.2.1 Introduction

This section addresses impact of the SPU on analyses/design features related to internal flooding due to leakage or a break in the CWS.

2.5.1.1.3.2.2 Acceptance Criteria

MPS3's licensing basis addresses design of systems to accommodate the effects of environmental conditions associated with normal operation, maintenance, testing, and postulated accidents (GDC-4). As addressed in SRP Section 10.4.5, Revision 2, compliance with GDC-4 is based on meeting the following:

- Providing means to prevent or detect and control flooding of safety-related areas so that the intended safety function of a system/component will not be precluded due to leakage from the CWS.
- Ensuring that malfunction of a component or piping of the CWS will not have unacceptable adverse effects on the functional performance capabilities of safety-related systems or components.

2.5.1.1.3.2.3 Description of Analyses and Evaluations

The impact of the SPU on the following analyses was evaluated:

- An analysis of flooding in the Turbine Building which determines the elevation of the water level in the building due to a circulating water line rupture, assuming that operator action to stop circulating water flow is delayed for 15 minutes.
- An analysis of flooding in the Turbine Building and design of pressure-release siding which determines that pressure-release siding installed on the west side of the Turbine Building is sufficient to limit the water level in the building to elevation 28 ft. (the maximum water level in the Turbine Building assuming no operator action is taken to stop circulating water flow following a circulating water expansion joint rupture).
- An analysis which determines that the maximum length of time that water would leak under the door connecting the Turbine Building with the Service Building and the Control Building due to flooding in the Turbine Building to an elevation of 28 ft., is very small (approximately 10 minutes); and, therefore, safety-related equipment in the adjacent buildings will not be jeopardized

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed in Section 2.5.1.1.3.1, the CWS is within the scope of plant license renewal. As addressed in the NRC's evaluation of this system, the NRC did not identify any concerns with MPS3's conclusions that there are no applicable aging effects requiring management for fiberglass pipe component types exposed to air or seawater, and no applicable aging effects requiring management for rubber expansion joints exposed to air or seawater. The SPU does not affect these conclusions.

2.5.1.1.3.2.4 Results

As discussed in Section 2.5.8, the CWS flow rate and operating pressures are unchanged at SPU conditions. There are no required modifications to the CWS or the Turbine Building as a result of the SPU that would affect the analyses associated with flooding due to a circulating water pipe rupture or expansion joint failure. The SPU does not add any safety-related equipment to the Turbine Building. Therefore, the SPU does not affect the analyses and design features related to internal flooding due to a circulating water pipe rupture or expansion joint failure.

2.5.1.1.3.3 Conclusion

DNC has reviewed the protection of safety-related equipment from flooding due to a break or leakage in the CWS. DNC concludes that the CWS will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-4. Since the CWS flow and operating pressures will remain unchanged for the SPU, and there are no modifications to the CWS or the Turbine Building resulting from the SPU that would affect the analyses associated with flooding due to a circulating water pipe rupture or expansion joint failure, the proposed SPU is acceptable with respect to flooding from the CWS.

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

2.5.1.2.1.1 Regulatory Evaluation

The DNC review concerns missiles that could result from in-plant component overspeed failures and high pressure system ruptures. The DNC review of potential missile sources covered pressurized components and systems, and high-speed rotating machinery. The DNC review was conducted to ensure that safety-related SSC's are adequately protected from internally generated missiles. In addition, for cases where safety-related SSC's are located in areas containing non-safety related SSC's, DNC reviewed the non-safety related SSC's to ensure that their failure will not preclude the intended safety function of the safety related SSC's. The DNC review focused on any increases in system pressures or component overspeed conditions that could result during plant operation, anticipated operational occurrences, or changes in existing system configurations such that missile barrier considerations could be affected.

The acceptance criteria for this review is:

- GDC-4 Insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with environmental conditions associated with normal operation, maintenance, testing and postulated accidents, including loss-of-coolant accidents

Specific review criteria are contained in SRP Sections 3.5.1.1 and 3.5.1.2 and guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Sections 3.5.1.1, Rev. 2 and 3.5.1.2, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, to 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 Station design relative to conformance to:

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4)

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCA's. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

In a letter from B. J. Youngblood (NRC) to J. F. Opeka (NNCO) dated June 5, 1985, Millstone 3 was granted an exemption for a period of two cycles of operation from those portions of General Design Criterion 4 which require protection of structures, systems, and components from the dynamic effects associated with postulated breaks in the reactor coolant system primary loop piping.

In Federal Register, Volume 51, No. 70, dated April 11, 1986, the NRC published a final rule modifying General Design Criterion 4 to allow the use of leak-before-break technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in pressurized water reactors. This rule excludes the need for the above exemption.

Structures, systems, and components important to safety are classified as QA Category 1 and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

Conformance to the requirements of GDC-4 ensures that safety-related SSC's are adequately protected from internally generated missiles. Systems and components located both inside and outside the containment have been examined to identify and classify potential missiles. Two broad categories of systems and components have been reviewed to determine the potential for generating missiles; pressurized components and high speed rotating machinery. Refer to FSAR Sections 3.5.1.1 for a discussion pertaining to internally generated missiles located outside of containment and FSAR Section 3.5.1.2 for a discussion pertaining to internally generated missiles located inside containment.

FSAR, MPS3 missile barrier components were evaluated for License Renewal. System and system component materials of construction, operating history and programs used to manage the aging effects are documented in NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Unit 2 and 3, dated August 1, 2005. With respect to the above SER the equipment and components credited with mitigating the effects of missiles is described in Section 2.4B and the program credited with managing equipment aging is described in Section 4.7B.2.

2.5.1.2.1.2 Technical Evaluation

2.5.1.2.1.2.1 Introduction

Safety related SSC's at MPS3 are protected from internally generated missiles from sources inside and outside of containment. These missiles are generated by failures in high energy systems and the overspeeding of rotating components. FSAR Section 3.5.1 discusses the measures taken to protect the safety related SSC's at MPS3 Station against internally generated missiles.

2.5.1.2.1.2.2 Description of Analyses and Evaluations

Missiles which are generated internally to the reactor facility (inside or outside containment) may cause damage to SSC's that are necessary for the safe shutdown of the reactor or for accident mitigation or may cause damage to the SSC's whose failure could result in a significant release of radioactivity. The potential sources of such missiles are valve bonnets and hardware retaining bolts, relief valve parts, instrument wells, pressure containing equipment (such as accumulators and high pressure bottles), high speed rotating machinery, and rotating components such as impellers and fan blades.

The DNC review focused on any increases in system pressures or component overspeed conditions due to the implementation of SPU that could result during plant operation, anticipated operational occurrences, or changes in existing system configurations such that missile barrier considerations could be affected.

MPS3 Class 1 valves that are part of systems subject to increased pressure as a result of the implementation of SPU were reviewed to reconcile operating parameter changes. As a result of this evaluation it was determined that implementation of SPU does not impact system pressures in a manner that would cause missile generation. As such, the existing missile protection measures remain effective for SPU conditions.

Refer to Section 2.5.1.2.2, Turbine Generator, for evaluations of the impact of turbine missiles.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 License Renewal Safety Evaluation Report for internally generated missiles. As stated in Section 2.5.1.2.1.1, internally generated missiles are within the scope of license renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with the evaluation of internally generated missile considerations at SPU conditions. There are no modifications to existing plant internally generated missile related support components. Thus, no new aging effects requiring management are identified.

2.5.1.2.1.2.3 Results

Since the SPU does not adversely impact the pressures in the systems that could generate missiles, the existing missile protection measures remain effective for SPU conditions. For plant areas containing safety-related SSC's, the SPU will not result in any changes to existing missile sources or add any new components that could become a new potential missile source. The SPU will also not result in any system configuration changes that would impact any existing missile barrier considerations.

The results of the evaluations demonstrate that the SPU will not impact safety related SSC's with respect to internally generated missile concerns and will continue to meet the MPS3 Station current licensing basis with respect to the requirements of GDC-4.

The SPU does not add new missile barrier components or modify any existing components that would change the license renewal evaluation boundaries. Therefore, no new aging effects requiring management are identified.

2.5.1.2.1.3 Conclusion

DNC has reviewed the changes in system pressures and configurations that are required for the proposed SPU. DNC concludes that the evaluation demonstrates that SSC's important to safety will continue to be protected from internally generated missiles following implementation of the proposed SPU and will continue to meet the current license basis with respect to GDC-4. Therefore, DNC finds that the proposed SPU is acceptable with respect to internally generated missiles.

2.5.1.2.2 Turbine Generator

2.5.1.2.2.1 Regulatory Evaluation

The turbine control system, steam inlet stop and control valves, low pressure turbine steam intercept and inlet control valves, and extraction steam control valves control the speed of the turbine under normal and abnormal conditions, and are thus related to the overall safe operation of the plant. The DNC review focused on the effects of the proposed SPU on the turbine overspeed protection features to ensure that a turbine overspeed condition above the design overspeed is very unlikely.

The acceptance criteria for the turbine generator are based on

- GDC-4 insofar as it relates to the protection of SSCs important to safety from the effects of turbine missiles by providing a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generating turbine missiles.

Specific review criteria are contained in the SRP, Section 10.2, and other guidance provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800), SRP Section 10.2, Rev. 2. As noted in FSAR Section 3.1, the MPS3 design bases are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The MPS3 design adequacy relative to the general design criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 turbine generator regarding conformance to

> GDC-4 is described in FSAR Section 3.1.2.4, General Design Criterion 4 – Environmental and Missile Design Bases.
>
> Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents, including LOCA’s. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.
>
> Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.
>
> Conformance to the requirements of GDC-4, with respect to overspeed protection, is also described in FSAR Section 3.5.1.3, Turbine Missiles. Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in the FSAR Section 3.2.5.

> FSAR Section 3.11 provides information to demonstrate that the safety-related electrical equipment is capable of performing designated safety-related functions while exposed to applicable normal, abnormal, test, accident, and post-accident environmental conditions. Protection against the dynamic effects associated with the postulated rupture of pipes is described in FSAR Section 3.6.

The turbine generator is described in the FSAR Section 10.2.2 and meets the guidelines of BTPs ASB 3-1 and MEB 3-1. The turbine generator description includes the turbine generator equipment, moisture separators, use of extraction steam for feedwater heating, and control functions that could influence operation of the reactor coolant system. The turbine overspeed system is also described in detail.

The turbine generator system was evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. The turbine generator is not within the scope of license renewal.

2.5.1.2.2.2 Technical Evaluation

2.5.1.2.2.2.1 Introduction

The main turbine train is comprised of one high-pressure turbine and three low-pressure turbines, all mounted on a common shaft. The steam flow path is first through the high-pressure turbine, through two moisture separator reheaters, then through a parallel path to three monoblock low-pressure turbines. The main turbine operates at a design speed of 1800 rpm. High-pressure steam is admitted to the high-pressure turbine through four 30” main steam lines. Each line is supplied with one 28” stop valve and one 20” control valve. A common manifold is provided between the two sets of valves. The turbine stop and control valves are controlled by the electro-hydraulic control system. This control system provides two independent valve groups for protection against overspeed for each steam admission line to the turbine. Steam leaving the high-pressure turbine passes through the moisture separator reheaters and the combined intermediate valves prior to entering the low-pressure turbines. The six combined intermediate valves are each equipped with an intercept valve and an intermediate stop valve, which are independently operated valves. These valves are also controlled by the electro-hydraulic control system. This valve arrangement allows control of steam flow to the low-pressure turbines and provides redundancy against an overspeed event.

Following a sudden turbine trip or load reduction, steam in the feedwater heaters, as well as water flashing to steam, could backfeed to the turbine, even with closure of the turbine stop valves and combined intermediate valves resulting in turbine overspeed. The extraction steam lines to the first through fourth point feedwater heaters contain extraction steam non-return valves to prevent turbine overspeeding due to reverse flow.

The electro-hydraulic control system provides a normal overspeed protection system and an emergency overspeed protection system to limit turbine overspeed. These are separate and independent systems. Normal overspeed protection is provided by the turbine load and speed control system, designed to limit turbine overspeed without a turbine trip. The normal speed governor modulates the turbine control valves to maintain desired speed load characteristics. If speed should increase above 100 percent rated, the control valves and intercept valves provide overspeed protection. The control valves will start to close above 100 percent of rated speed and be fully closed at 105 percent of rated speed. The intercept valves will begin to close at 105 percent of rated speed and be fully closed at 107 percent of rated speed. The emergency overspeed protection system is part of the emergency trip system, designed to trip the turbine if turbine speed reaches 110 percent of rated speed. Overspeed protection is provided by a mechanical overspeed trip mechanism that trips the turbine stop, control, and combined intermediate valves in 0.2 seconds through the release of hydraulic pressure. The electrical backup overspeed sensor will trip these same valves at 111 percent of rated speed by independently deenergizing the hydraulic fluid system.

In-service inspection and testing of turbine components is described in U3-24-TOP-PRG, Turbine Overspeed Protection Maintenance and Testing Program. This maintenance and testing program outlines the dismantled inspection frequencies for the high-pressure turbine, the low-pressure turbines, and the main turbine valves (control, stop and combined intermediate). It also prescribes the testing and calibration requirements for the overspeed protection control system and the overspeed protection valves.

Instrumentation ranges, scaling and setpoints are discussed in Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems.

2.5.1.2.2.2.2 Description of Analyses and Evaluations

General Electric (GE), the turbine manufacturer, performed a stretch power uprate study to assess the capability of existing equipment to handle a power uprate to 107 percent. This study included a detailed thermal evaluation and mechanical evaluation of the main turbine and turbine auxiliaries based on the original valves-wide-open (VWO) vendor heat balance. Details are provided in “Stretch Power Uprate Study Report – Steam Turbine/Generator for Dominion Nuclear Connecticut Millstone Power Station Unit 3,” dated November 2006. DNC completed a Technical Evaluation to supplement the GE report regarding the capability of existing equipment to support the proposed SPU. Technical Evaluation M3-EV-06-0015, Rev. 0, dated December 19, 2006 documents DNC’s findings.

The GE evaluation analyzed the following components:

- High-pressure turbine and low-pressure turbine shells, casings, and bolting
- Low-pressure turbine atmospheric relief diaphragms
- High-pressure turbine and low-pressure turbine diaphragms (including expansion and clearances)
- High-pressure turbine and low-pressure turbine buckets
- Turbine rotors, couplings, and coupling bolting
- Rotor dynamics, stability, and torsional stresses (including fatigue life expenditure)
- Thrust bearing and journal bearings
- Cross-around relief valves for moisture separator reheater protection

- Main steam leads piping and cross-around piping
- Main stop valves, main control valves, and combined intermediate valves
- Overspeed sensitivity and protection

The main turbine power output is limited by the volumetric flow through the high-pressure turbine. The GE evaluation assessed the main turbine's ability to handle the additional volumetric flow caused by SPU by a comparison to the GE original VWO heat balance. The DNC Technical Evaluation performed a similar review based on initial plant startup testing results and subsequent operating performance.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for the turbine generator. As stated in Section 2.5.1.2.2.1, the evaluation of the turbine generator was not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for license renewal and they remain valid for the SPU conditions.

2.5.1.2.2.2.3 Turbine Results

The GE assessment was a heat balance that represented uprated conditions with 10 percent SG tube plugging and 3 percent flow margin. The DNC Technical Evaluation focused on a review of testing results from initial power ascension and warranty run. The testing included a VWO test at 100 percent power in full arc admissions mode. A VWO volumetric flow of 1982.3 cu.ft/s was achieved, which is a 4.4 percent excess flow over the GE design VWO volumetric flow of 1899.4 cu.ft/s. Additionally, MPS3 operated for the majority of the 1993 cycle with the reheat supply to the moisture separators isolated due to tube leaks. This condition resulted in an excess flow capacity of 7 percent. At a power uprate value of 107 percent, the calculated volumetric flow rate with 0.6 percent SG tube plugging is 1874.5 cu.ft/s, which represents an approximate 5.8 percent flow margin to the initial power ascension testing VWO volumetric flow. The flow margin is 3.0 percent with 10 percent SG tube plugging. Based on the results of these analyses, DNC has concluded that the existing high-pressure turbine has sufficient margin (minimum of 3 percent) to support a 7 percent uprate.

The effects of the proposed SPU on normal operation, maintenance, testing, and overspeed protection were reviewed by General Electric and DNC. The reviews concluded that the turbine is adequate for operation at SPU conditions. The following items were considered in this review:

- The normal operating turbine "running" speed of 1800 rpm will not change as a result of the power uprate.
- No plant hardware changes will be made to any mechanical system components (low-pressure turbines, and main turbine valves) as a result of the power uprate. Since the completion of the General Electric evaluation, DNC performed high-pressure turbine rotor phased array testing of the tangential-entry dovetail regions of the wheel rim during the recent 3R11 plant outage. The test revealed indications on the turbine first stage wheel. DNC is currently evaluating options for addressing this condition prior to implementing the SPU. The available options include:

- installing a new HP rotor
- disassembling first stage buckets during the 3R12 outage, conducting inspections, removing indications and possible repairs

- Maintenance and inspection of the high-pressure turbine, low-pressure turbines, and main turbine valves (control, stop, and combined intermediate valves), including frequencies, will not change as a result of the power uprate.
- Testing and calibration of the overspeed protection control system and overspeed protection valves will not change as a result of the power uprate. No changes to testing methodologies or testing frequencies will occur.
- The existing overspeed trip setpoint of 110 percent is adequate to ensure that the design overspeed limit of 120 percent will not be exceeded, and the overspeed trip setpoint will not change as a result of the power uprate. The turbine rotating elements are unchanged, and there is no significant change to entrained steam volume as a result of this power uprate; therefore, there is no impact to overspeed characteristics.
- The design overspeed limit of 120 percent will not change as a result of the power uprate.
- MPS3 high-pressure turbine and low-pressure turbines remain of the monoblock design.
- The current probability of attaining an overspeed of 120 percent or greater (maintaining proper testing frequencies) is 1.7 x 10-6 and will not change as a result of the power uprate.
- Power uprate main steam pressure and temperature are at or below the existing pressure and temperature of 973 psia and 541°F, respectively.

The NRC requires turbine overspeed protection to ensure that the probability of generating turbine missiles is kept within established limits. The accepted methodology was based on maintaining the probability of generating a turbine missile below the 1 x 10-5 limit for an unfavorably oriented turbine. MPS3 is unfavorably oriented. This methodology included consideration of the probability of unit overspeed, wheel materials, in-service inspection capabilities, and the potential for wheel containment by stationary turbine structures. The resultant probability is also based on testing affected components while maintaining the prescribed inspection intervals. Maintenance and testing requirements are contained in U3-24-TOP-PRG. There are no changes to the program maintenance and testing requirements as a result of the proposed power uprate. MPS3 is only susceptible to ductile rotor failure with the current monoblock design. The probability of ductile failure is a function of rotor speed, temperature, and material tensile strength. Since the overspeed trip setpoint is not altered, operating temperature is not increased, and the existing rotors are not changed, the probability of ductile failure has not changed. Therefore, the probability of generating a turbine missile remains acceptable, since previously evaluated equipment is utilized and established test intervals ensure the unit remains below design overspeed.

2.5.1.2.2.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the turbine generator. DNC concludes that the evaluation has adequately accounted for the proposed SPU effects on turbine overspeed, and that the turbine generator will continue to provide adequate turbine overspeed protection to minimize the probability of generating turbine missiles. Based on this, DNC concludes that the turbine overspeed protection features will continue to provide adequate protection to meet the MPS3 current licensing basis with respect to the requirements of GDC-4 following proposed SPU implementation. Therefore, DNC finds the proposed SPU acceptable with respect to the turbine generator.

2.5.1.3 Pipe Failures

2.5.1.3.1 Regulatory Evaluation

DNC conducted a review of the plant design for protection from piping failures outside containment to ensure (1) such failures would not cause the loss of needed functions of safety-related systems and (2) the plant could be safely shut down in the event of such failures. The DNC review of pipe failures included high and moderate energy fluid system piping located outside of containment. The review focused on the effects of pipe failures on plant environmental conditions, control room habitability, and access to areas important to safe control of post-accident operations where the consequences are not bounded by previous analysis.

The acceptance criteria for pipe failures are based on:

- GDC-4, insofar as it requires that SSC's important to safety be designed to accommodate the dynamic effects of postulated pipe ruptures, including the effects of pipe whipping and discharging fluids.

Specific review criteria are contained in SRP Section 3.6.1 and guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 3.6.1, Rev. 1.

MPS3 took the following exceptions to SRP 3.6.1, Rev 1:

1. SRP 3.6.1, BTP ASB 3-1, B.1.a (1) requires an arbitrary split on the main steam and feedwater systems at a location proximate to essential systems. MPS3 does not postulate arbitrary splits.

2. SRP 3.6.1, BTP ASB 3-1, B.1.a (2) suggests main steam and feedwater pipes not be routed in the vicinity of the control room. MPS3 has the main steam and feedwater routed in the vicinity of the Control Room.

3. SRP 3.6.1, BTP ASB 3-1, B.2.a states that essential systems and components should be designed to meet the seismic design criteria of R.G. 1.29. For the auxiliary steam and the hot water heating systems, MPS3 designs the electrical detection and actuation devises to Class 1E requirements and locates them in Category 1 buildings.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to conformance to:

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4), as follows:

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

  Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

  FSAR Chapter 3 provides the details of the environmental and dynamic effects to which the structures, systems, and components important to safety are designed.

FSAR Section 3.6.1, Postulated Piping Failures in Fluid Systems Inside and Outside Containment, describes the design criteria and bases for protecting essential equipment from the effects of piping failures inside and outside of Containment.

Additional details that define the licensing basis for piping systems related to pipe rupture effects are described in FSAR Section 3.6.2, Determination of Break Locations And Dynamic Effects Associated With The Postulated Rupture of Piping.

The MPS3 barriers used to mitigate HELBs and internal floods were evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838, Section 2.4B.2 is applicable to the HELB and flood barriers in MPS3 structures.

2.5.1.3.2 Technical Evaluation

2.5.1.3.2.1 Introduction

High energy line break analysis identifies high and moderate energy piping system lines subject to failure and the plant safety-related equipment potentially impacted by piping failures. High energy line break analysis determines the environmental effects resulting from the piping failures, and the hazards analyses identify the protection measures required to mitigate the effects of the piping failures. The environmental conditions resulting from this analysis are provided as input into the environmental qualification program. (Refer to Section 2.3.1, Environmental Qualification of Electrical Equipment. Refer also to Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects, for discussion of the impact of the SPU on pipe break locations.)

The evaluation of pipe breaks outside containment considered the zones within the plant which contain systems required for safe shutdown and/or systems required to mitigate the effects of postulated pipe breaks.

2.5.1.3.2.2 Description of Analyses and Evaluations

The impact of the SPU on HELB analyses and building flooding analyses is evaluated. The impact of the SPU on the hazards analyses is also addressed.

The evaluation of the impact of the SPU on HELB analyses considers the HELB events that are bounding with respect to the temperature and pressure conditions for each building or building area containing essential equipment, i.e., safety-related equipment required to operate for mitigation of the HELB event.

The evaluation of the high/moderate energy line break events addresses the impact of the SPU operation on the current analyses of flooding in plant structures and effects on safety-related equipment.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 License Renewal Safety Evaluation Report for the internal hazards from piping failures. As stated in the SER, Section 2.4B.2 of NUREG-1838, barriers used to mitigate HELBs and internal floods are evaluated within the structure that contains them. Section 3.5B.2 of the SER identifies the programs that manage the aging effects related to structures, including the Structures Monitoring Program. Since the SPU does not add any new barriers or modify existing barriers used to resist the effects of HELB or flooding, it does not affect the evaluation of these barriers contained in the SER (NUREG-1838).

2.5.1.3.2.3 Results

High Energy Line Break Analyses

The identification of the high energy and moderate energy lines does not change as a result of the SPU. The changes to system process conditions will not add or delete systems from the high energy or moderate energy category. The evaluations for SPU conditions do not create any new or revised pipe break locations from those identified in the FSAR (Refer to Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects). Because the high and moderate energy boundary definitions have not changed and no new equipment has been added that requires protection from the effects of a pipe break, the existing high and moderate energy pipe break hazards evaluations are not affected by SPU operating conditions.

The FSAR Tables 3.6-2 and 3.6-4 for high energy and moderate energy, respectively, identify all the high and moderate energy lines in proximity to essential equipment. The list of plant essential equipment is provided in FSAR Table 3.6-5. Essential equipment is necessary to bringing the plant to cold shutdown and protects the public in the event of individual HELB/MELB failures. Since the SPU operation does not require the addition of essential equipment nor change lines from moderate energy to high energy, SPU operation does not change the listing of applicable systems in these tables.

Main Steam Valve Building (MSVB)

The high energy lines in the MSVB are the main steam, feedwater, main steam safety valve vents and drains, steam generator blowdown, steam generator chemical feed, hot water heating and turbine plant miscellaneous drain lines.

The main steam, steam generator blowdown and the feedwater lines penetrating the Containment have break exclusion zones from the Containment penetration to the outboard rupture restraint. The limiting main steam line break is the 1 square foot break required for equipment qualification within the break exclusion zone of the main steam system. The analysis of the main steam breaks in the MSVB changed the temperature profile peak to 565°F from 500°F. The peak pressure remains bounded by the existing pressure profile. The impact of the accident temperature is addressed in the Section 2.3.1, Environmental Qualification of Electrical Equipment.

The MSVB hazards analysis has been reviewed to identify any changes for the SPU. Since there are no spray or jet impingement targets, the only SPU impact is the revised temperature profile for the equipment qualification.

Auxiliary Building

The high energy lines in the Auxiliary Building identified in FSAR Table 3.6-2 are the normal charging lines, normal letdown, seal water injection, high pressure injection, auxiliary steam, hot water heating, boron recovery, containment vacuum pump discharge, auxiliary condensate, reactor plant gaseous drains, nitrogen gas supply, radioactive gaseous waste, reactor plant sampling and reactor plant aerated drains. The operating conditions for these systems are unchanged by SPU. The temperature and pressure effects associated with HELBs continue to remain bounding for the qualification of the essential equipment.

The SPU does not impact the Auxiliary Building hazards analysis.

Turbine Building

The Turbine Building has been analyzed in the FSAR for equipment qualification and for barrier protection for the Control Room. The bounding temperature condition for HELB in the Turbine Building is the rupture of the main steam system. This condition has been previously evaluated for equipment qualification at 102 percent power. This previously performed temperature analysis is no longer bounding for SPU conditions. There are two component types listed in the Equipment Qualification Master List (EQML) that are in the Turbine Building. The EQML will be revised to remove these components as they do not require environmental qualification. FSAR Table 3.6-5 lists two valves in the Turbine Building as essential for shutdown in the event of a HELB in the Auxiliary Building. Since there is no equipment in the Turbine Building requiring qualification for breaks in the Turbine Building, a revised temperature profile is not necessary. The pressure for the Turbine Building, resulting from a main steam line break in the Turbine Building does not change for SPU.

No hazards analysis is necessary for the Turbine Building based on the discussion above since there is no safety related equipment in the building and no essential shutdown equipment that needs protection for HELBs in the Turbine Building.

Engineered Safety Features (ESF) Building

The high energy lines that are in the ESF Building are main steam, auxiliary steam, turbine plant miscellaneous drains, and auxiliary feedwater. No breaks are postulated in the main steam piping or the turbine plant miscellaneous drains. The main steam line to the turbine driven auxiliary feedwater pump is not pressurized during normal plant operations. The main steam up to the isolation valve supplying the turbine drive is within the break exclusion area of the main steam system. The turbine plant miscellaneous drain lines are less than 1 inch and therefore not subject to the postulation of breaks. The auxiliary feedwater system lines that are in proximity to each other after leaving the auxiliary feedwater pump cubicles are protected from failure due to pipe whip as they are all the same pipe size and wall thickness which can't break pipes of the same size and wall thickness. The other high energy lines are protected by separation distance and/or barriers provided by the ESF area cubicle walls.

The ESF Building hazards analysis is not impacted by the SPU.

Fuel Building

The FSAR Table 3.6-2 lists the hot water heating as the only high energy line in the Fuel Building. The hot water heating system is not impacted by the SPU. The environmental conditions in the Fuel Building are not changed by the SPU.

The Fuel Building hazards analysis is not impacted by the SPU operation.

Control Building

There are no high energy lines in the Control Building. Flooding due to moderate energy pipe cracks is addressed below.

Summary

In summary, since system operating temperatures and pressures generally remain unchanged; the protection against high energy line breaks is not impacted by the SPU. One plant area environment that is impacted by SPU operation is the MSVB. The postulated break in the main steam results in an increase in the peak temperature in this building area. The qualification of the equipment to the new conditions is discussed in Section 2.3.1, which addresses electrical equipment qualification.

Building Flooding Analyses

The flooding review included evaluation of the impact of SPU operation on the current analyses of flooding in plant structures and effects of the flooding on safety-related equipment, as follows:

Auxiliary Building

The limiting sources of flooding in the Auxiliary Building are (1) a moderate energy pipe crack in a service water system line located at Elevation 4 ft. 6 in. of the building, and (2) a moderate energy pipe crack in a fire protection – water system line also located at Elevation 4 ft. 6 in. of the building. The SPU does not affect the flow rates or pressures in the SWS. The SPU does not affect the flow rates or pressures of the fire protection - water system. Therefore, the SPU does not affect the analysis results regarding flooding from pipe cracks in the Auxiliary Building.

ESF Building

The limiting source of flooding in either of the motor-driven AFW pump cubicles or the quench spray pump cubicle is a HELB in a AFW system discharge line of a motor-driven AFW pump in one of the AFW pump cubicles (faulted AFW pump cubicle). The flood water in the faulted AFW pump cubicle is distributed to the non-faulted AFW pump cubicle and the quench spray pump cubicle through door gaps. The analysis assumes that the motor-driven AFW pump operates at runout flow rate. The SPU does not affect motor-driven AFW pump head performance, and therefore does not affect the analysis results regarding flooding from a HELB in one of the motor-driven AFW pump cubicles.

The limiting source of flooding in either of the residual heat removal pump cubicles at Elevation 24 ft. 6 in. is a moderate energy pipe crack in a quench spray system line in the cubicle on the floor above. The SPU does not affect the flow rates/pressures in the QS system. Therefore, the SPU does not affect the analysis results regarding flooding from a pipe crack in a cubicle above the RHR pump cubicles.

The limiting source of flooding in the 3 cubicles on the east side of the ESF Building at Elevation 24 ft. 6 in. is a moderate energy pipe crack in a SWS line. The SPU does not affect the flow rates or pressures in the SWS. Therefore, the SPU does not affect the analysis results regarding flooding from a pipe crack in the 3 cubicles on the east side of the ESF Building.

The limiting source of flooding in each of the 2 containment recirculation pump cubicles at Elevation (-) 34 ft. 9 in. is a HELB in an AFW system line. The analysis assumes a motor-driven AFW pump operates at runout flow rate. The SPU does not affect motor-driven AFW pump head performance, and therefore does not affect the analysis results regarding flooding from a HELB in the RS pump cubicles.

Fuel Building

The Fuel Building flooding analysis evaluates the potential for flooding on the four major floors at Elevations 52 ft. 4 in., 35 ft. 10 in., 24 ft. 6 in., and 11 ft. 0 in. Flood water from upper elevations of the building flows to the tunnel floor at Elevation (-) 9 ft. The limiting source of flooding in the tunnel is a moderate energy pipe crack in a reactor plant component cooling water system line. The flood height in the tunnel as a result of the pipe crack is derived from the total volume of the RPCCW surge tank. The volume of water in the RPCCW surge tank at SPU conditions, which increases less than three percent relative to the current volume, is less than the total volume of the surge tank. Therefore, the SPU does not affect the analysis results regarding flooding from a pipe crack in the Fuel Building.

MSVB

The limiting source of flooding in the MSVB is a moderate energy pipe crack in the RPCCW system supply to the steam generator blowdown system containment penetration coolers. The maximum flood height is determined using the volume of the RPCCW surge tank. The volume of water in the RPCCW surge tank at SPU conditions, which increases less than three percent relative to the current volume, is less than the total volume of the surge tank. Therefore, the SPU does not affect the analysis results regarding flooding from a RPCCW system pipe crack in the MSVB.

Hydrogen Recombiner Building

The Hydrogen Recombiner Building flooding analysis identifies the limiting source of flooding as a moderate energy line crack in a RPCCW system line. Evaluation shows that the changes in RPCCW system flow rates and pressures due to the SPU are as follows: increases in operating flow rates are less than five percent, and increases in pressures are less than one percent. Therefore, the SPU does not affect the analysis results regarding flooding from a pipe crack in the Hydrogen Recombiner Building.

Control Building

The Control Building flooding analysis evaluates the potential for flooding at Elevations 64 ft. 4 in., 46 ft. 0 in., 24 ft. 6 in., and 4 ft. 6 in.

At Elevation 64 ft. 4 in., a moderate energy pipe crack in a SWS line in the Mechanical Equipment Room and a moderate energy pipe crack in a SWS line in the Chiller Room are evaluated. The SPU does not affect the flow rates or pressures in the SWS.

At Elevation 46 ft. 0 in., a moderate energy pipe crack in a control building chilled water system line empties the entire volume of this system into the Instrument Rack and Computer Rooms. At Elevation 24 ft. 6 in., flooding due to a moderate energy pipe crack in a control building chilled water system line empties the entire volume of this system into the cable spreading area. At Elevation 4 ft. 6 in., a moderate energy pipe crack in a control building chilled water system line empties the entire volume of the this system into the West Switchgear Room. The control building chilled water system is not affected by the SPU.

Based on the above discussion, the SPU does not affect the analysis results regarding flooding from pipe cracks in the Control Building.

Emergency Generator Enclosure

The Emergency Generator Enclosure flooding analysis identifies the limiting source of flooding as a moderate energy line crack in a 10 inch SWS line. The SPU does not affect the flow rates or pressures in the SWS. Therefore, the SPU does not affect the analysis results regarding flooding from a pipe crack in the Emergency Generator Enclosure.

Service Water Pump Cubicles

The Service Water Pump Cubicles flooding analysis states that flooding in one Service Water Cubicle will not affect equipment in the redundant cubicle. Any flooding originating in a Service Water Pump Cubicle will be confined to that cubicle until the level reaches Elevation 36 ft., where overflow will occur to the circulating water pump compartment. Flooding due to a crack in an SWS line or a domestic water line will be limited to the level where the two SWS pump motors in that cubicle become submerged (the top of the pump motors is at Elevation 26 ft. 6 in.). The SPU does not affect the arrangement of the Service Water Pump Cubicles, and therefore does not affect the analysis conclusions regarding flooding in a Service Water Pump Cubicle.

The Service Water Pump Cubicles flooding analysis also addresses flooding of the Access Enclosure (located below the Service Water Pump Cubicles) due to failure of any line within the enclosure. The postulated failure could flood the entire room. The SPU does not affect the analysis conclusions regarding flooding in the Access Enclosure.

Service Building

The Service Building flooding analysis evaluates the potential for flooding at Elevations 52 ft. 6 in., 49 ft. 6 in., 38 ft. 6 in., 24 ft. 6 in., and 4 ft. 6 in. The analysis states that the most extreme failure is a moderate energy pipe crack in a fire protection - water system line at Elevation 52 ft. 6 in. The SPU does not affect the flow rates or pressures of the fire protection- water system, and therefore does not affect the analysis results regarding flooding from a pipe crack in the Service Building.

Waste Disposal Building

The Waste Disposal Building flooding analysis shows that the limiting source of flooding in the building is a moderate energy pipe crack in a primary grade water system line. The analysis assumes that 100,000 gallons from a primary grade water storage tank drains into the building. The SPU does not affect the flow rates or pressures of the primary grade water system, and therefore does not affect the analysis results regarding flooding from a pipe crack in the Waste Disposal Building.

Condensate Polishing Building

The Condensate Polishing Building flooding analysis indicates that any flooding in the building will flow into the Turbine Building. The analysis states that the limiting source of flooding in the building is from a condensate system line, but that the effects of flooding from this line is bounded by a circulating water system line break in the Turbine Building (refer to Section 2.5.1.1.3, Circulating Water System (CWS)). The SPU does not affect this analysis conclusion regarding flooding in the Condensate Polishing Building.

Auxiliary Boiler Enclosure

The Auxiliary Boiler Enclosure flooding analysis indicates that any flooding in the Auxiliary Boiler Enclosure will flow into the Turbine Building and that any flooding as a result of failure of the vessels in the enclosure is insignificant in comparison with the flood level resulting from a circulating water system line break in the Turbine Building (refer to Section 2.5.1.1.3, Circulating Water System (CWS)). The SPU does not affect these analysis conclusions regarding flooding in the Auxiliary Boiler Enclosure.

Summary

Based on the above evaluation of impact of the SPU on the current building flooding analyses, the SPU does not affect the conclusions in these analyses regarding the effects of flooding on safety-related equipment.

Other Supporting Flooding Analysis

In a current analysis, a review is performed of the current MPS3 building flooding calculations to evaluate the effect of including as flooding sources high and moderate energy lines containing water at a temperature of greater than or equal to 212°F. The analysis concluded that no building flooding analyses are affected except the MSVB flooding analysis. Flooding from the HELB of a SG blowdown system line in the MSVB at current plant conditions was evaluated. Since SG blowdown system conditions at the SG under SPU conditions are not significantly different from those at current conditions and no new safety-related equipment is added to the MSVB for the

SPU, the SPU does not affect the current analysis results and conclusions regarding a HELB in the SG blowdown system in the MSVB.

2.5.1.3.3 Conclusion

DNC concludes that the evaluation has adequately accounted for the effects of the proposed SPU with respect to protection against the environmental and dynamic effects of postulated piping failures in fluid systems outside containment. DNC concludes that structures, systems, and components important to safety will continue to meet the current licensing basis with respect to GDC- 4 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU is acceptable with respect to protection against postulated piping failures in fluid systems outside containment.

2.5.1.4 Fire Protection

2.5.1.4.1 Regulatory Evaluation

The purpose of the fire protection program is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The DNC review focused on the effects of the increased decay heat on the plant's safe shutdown analysis to ensure that structures, systems, and components required for the safe shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe shutdown following a fire.

The acceptance criteria for fire protection are based on:

- 10 CFR 50.48 and associated Branch Technical Position, CMEB 9.5-1, insofar as they require the development of a fire protection program to ensure, among other things, the capability to safely shut down the plant.
- GDC-3, insofar as it requires that (a) safety-related structures, systems, and components be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on safety-related structures, systems, and components.
- GDC-5, insofar as it requires that safety-related structures, systems, and components not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions.

Specific review criteria are contained in SRP Section 9.5.1, and guidance is provided in Attachment 1 to Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800 "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants," July 1981, SRP Section 9.5.1, Rev. 2.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 Station design relative to conformance to the following:

- GDC-3 is described in FSAR Section 3.1.2.3, Fire Protection (Criterion 3)

  The design of MPS3 minimizes the probability and effect of fires and explosions on structures, systems, and components important to safety. Noncombustible and heat-resistant materials are used wherever practical throughout the unit. Fire detection and fire suppression systems of sufficient capacity and capability minimize the adverse effects of fires on structures, systems, and components important to safety. Fire suppression systems are designed to assure that rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

FSAR Section 9.5.1 and the MPS3 Fire Protection Evaluation Report describe the fire protection system in detail.

- GDC-5 is described in FSAR Section 3.1.2.5, Fire Protection (Criterion 5)

  The fire protection system is identified in FSAR Section 3.1.2.5 as a system not important to safety within the definition of GDC-5, but which is shared by the three Millstone units (MPS1, MPS2, and MPS3).

The Fire Protection License Condition for MPS3 is given in Paragraph 2.H of the Renewed License No. NPF-49, dated November 28, 2005, as follows:

> DNC shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility and as approved in the SER (NUREG-1031) issued July 1984 and Supplements Nos. 2, 4, and 5 issued September 1985, November 1985, and January 1986, respectively, subject to the following provision: The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

As described in FSAR Section 9.5.1, a Fire Protection Program has been established by an Administrative Control Procedure at Millstone Unit 3. This program establishes the fire protection policy for the protection of structures, systems, and components important to the safety of the plant and the procedures, equipment, and personnel required to implement the program.

FSAR Section 9.5.1 identifies the following as source documents which form the basis for the MPS3 Fire Protection Program:

- 10 CFR 50, Appendix A, “General Design Criteria for Nuclear Power Plants.”
- 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.”
- NUREG-0800, Nuclear Regulatory Commission (NRC), Branch Technical Position, CMEB 9.5-1 (herein referred to as “BTP 9.5-1).
- NRC Generic Letter 86-10, “Implementation of Fire Protection Requirements.”

FSAR Section 9.5.1 identifies the following as compliance documents in terms of addressing and complying with the source documents:

- Fire Protection Program Manual
- MPS3 Fire Protection Evaluation Report (FPER)
- MPS3 Fire Fighting Strategies
- MPS3 BTP 9.5-1 Compliance Report

As described in FSAR Section 9.5.1, the Fire Protection Program Manual has been developed to ensure that a single fire will not cause an unacceptable risk to public health and safety, will not prevent the performance of necessary safe shutdown functions, and will not significantly increase the risk of radioactive release to the environment.

The FPER represents the operating license (OL) fire protection program submittal to the NRC for MPS3.

The Technical Requirements Manual (TRM), Section 7.4, Fire Protection – Safe Shutdown Requirements, addresses the additional Operability requirements for safe shutdown components not addressed in the Technical Specifications or other sections of the TRM.

Plant programs credited for aging management were evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, dated August 1, 2005, defines the scope of license renewal. NUREG-1838 Section 3.0.3.2.7 is applicable to the Fire Protection Program.

2.5.1.4.2 Technical Evaluation

2.5.1.4.2.1 Introduction

The Fire Protection Program Manual describes the MPS3 Fire Protection Program. This program establishes the fire protection policy for the protection of structures, systems, and components important to plant safety, and the procedures, equipment and personnel required to implement the program. The fire protection program extends the concepts of defense-in-depth to fire protection in areas important to safety, with the following objectives:

- Prevent fires from starting
- Rapidly detect, control and promptly extinguish those fires that do occur
- Provide protection for SSCs important to safety so that a fire that is not promptly extinguished by fire suppression activities will not prevent safe plant shutdown.

The FPER provides a discussion of the following:

- Historical background for MPS3 fire protection design
- Administration
- Plant Design Features
- Fire Hazards Analysis
- Safe Shutdown Evaluation
- Support Systems
- Resolution of Safe Shutdown Evaluation Problem Areas
- Operator Actions Required Following a Fire
- Comparison of MPS3 Plant Design to BTP CMEB 9.5-1 Guidelines
- Summary of Comparison with 10 CFR 50, Appendix R

The BTP 9.5-1 Compliance Report complements the FPER and documents the analysis results that demonstrate that MPS3 can be placed in a cold shutdown condition following a design basis fire, as required by BTP 9.5-1. The following items are addressed in the BTP 9.5-1 Compliance Report:

- Fire Areas
- Shutdown Systems and Methods
- Deviations to BTP 9.5-1
- Electrical
- Manual Action Feasibility
- Component Damage Summary Sheets
- Request and Deviation Analyses
- Cable Routing Matrices

2.5.1.4.2.2 Description of Analyses and Evaluations

The SPU impact on the following FPER elements is evaluated:

- Administration
- Plant Design Features
- Fire Hazards Analysis
- Safe Shutdown Evaluation
- Support Systems
- Resolution of Safe Shutdown Evaluation Problem Areas
- Operator Actions Required Following a Fire

A discussion of the impact of the SPU on other supporting analyses/evaluations is included.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for the Fire Protection Program. The Fire Protection Program is within the scope of license renewal. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating fire protection system components at SPU conditions does not add any new or previously unevaluated materials. Fire protection system component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.1.4.2.3 Results

2.5.1.4.2.3.1 Administration

Administration includes the organization, fire brigade and training. The fire protection organization, including the fire brigade is unaffected by the SPU. There are no changes to the responsibilities, reporting relationships, or fire brigade composition as a result of the SPU.

2.5.1.4.2.3.2 Plant Design Features

These design features include the site water supply, fixed suppression systems, portable extinguishers, fire detection and alarm systems, ventilation capabilities for smoke removal, access and egress routes, emergency lighting systems, and communication systems. The fire protection plant design features listed above are unchanged as a result of the SPU. The existing design features adequately address the fire protection requirements at SPU conditions.

2.5.1.4.2.3.3 Fire Hazards Analysis

The fire hazards analysis includes the evaluation criteria, analysis method, analysis assumptions, and fire areas and zones. The existing MPS3 fire hazards analysis provides reasonable assurance that a fire will not cause an unacceptable risk to public health and safety, does not prevent the performance of necessary safe shutdown functions, and does not increase the risk of radioactive release to the environment. The fire hazards analysis addresses BTP 9.5-1, C.1.b regarding the identification of hazards and appropriate protection in locations where safety-related losses can occur. MPS3 performed a plant fire suppression system evaluation to ensure that neither an inadvertent operation nor rupture of fire suppression system piping would affect the ability to achieve safe plant shutdown. Conclusion from that evaluation were reviewed for SPU impact. There are no changes or adverse impacts to the fire hazards analysis as a result of the SPU.

2.5.1.4.2.3.4 Safe Shutdown Evaluation

Safe Shutdown Analysis

The MPS3 BTP 9.5-1 Compliance Report documents the analysis results demonstrating that MPS3 can be placed in cold shutdown following a design basis fire. Each required function to achieve and maintain safe shutdown was evaluated by fire area. These functions are as follows:

- Reactivity control (reactor trip and boration capability)
- Reactor coolant inventory control
- RCS pressure control
- Decay heat removal
- Process monitoring
- Support (systems required to support the above functions)

In addition to the above functions, the following systems required to support these functions were also evaluated.

- Main steam system
- Auxiliary feedwater system
- Chemical and volume control system
- High pressure safety injection system
- Reactor coolant system
- Residual heat removal system
- Reactor plant component cooling water system
- Service water system

The safe shutdown analysis identifies fire-induced failures that affect the plant and the operator actions that can be used to compensate for these failures. The shutdown analysis addresses the worst-case fire damage for each fire area. It also accounts for both the availability of offsite power and the loss of offsite power following a fire.

Cold Shutdown Time Following Reactor Trip

Analyses demonstrate that MPS3 can be placed in cold shutdown within 72 hours after a reactor trip following a fire at SPU conditions. The analysis assumes that instrument air is unavailable and that one RHR train and supporting systems is available. The analyses confirm the time to cold shutdown after a reactor trip for the three limiting scenarios with respect to the 72 hour shutdown criteria:

- Fire Area AB-1, North (charging and reactor plant component cooling water system components): 66 hours
- Fire Area AB-1, South (charging and reactor plant component cooling water system components): 68 hours
- Fire Areas CB-8, CB-9, CB-11A, CB-11B (Control Room, Cable Spreading Room, Instrument Rack Room): 46 hours

Control Room Fire Transient Analysis

The Control Room fire transient analysis is performed for a postulated fire resulting in loss of all charging due to a fire in the Control Room, Cable Spreading Room or Instrument Rack Room. The controls from the Control Room are transferred to the Auxiliary Shutdown Panel. The revised analysis uses the new pressurizer level program as an initial condition. The change in the pressurizer level program is as a result of the SPU. The current analysis demonstrates that the RCS would not reach saturation conditions and that pressurizer level would remain on scale with or without loss of offsite power. The revised analysis performed at SPU conditions confirms that SPU does not impact the required operator action times or the capability to maintain pressurizer level on scale during the transient.

Charging Cubicle Fire Transient Analysis

A fire in fire area AB-1, South, could potentially result in the loss of all three charging pumps. This is determined to be one of the limiting transients required to ensure that the plant response was within the bounds of a normal loss of offsite power analysis. The current analysis demonstrates that the RCS would not reach saturation conditions and that pressurizer level would remain on scale with or without loss of offsite power. The analysis is revised for SPU conditions to account for the change in the pressurizer level program. The revised analysis performed at SPU conditions confirms that SPU does not impact the required operator action times or the capability to maintain pressurizer level on scale during the transient.

For the above-described limiting transients, MPS3 does not rely on less than full capability systems (e.g., reduced capability makeup pump). Moreover, pressurizer level is shown to remain on scale throughout the transients. The fuel remains covered, and therefore fuel design limits are not exceeded

RCS High/Low Pressure Interfaces

The BTP 9.5-1 Compliance Report identifies the boundaries between the high pressure RCS and adjacent low-pressure systems. Only those flow paths isolated by electrically controlled and/or powered components are of concern. The current systems analysis identified two high/low pressure system boundaries that are isolated by motor-operated valves: the RHR suction lines. Each suction line has two normally closed motor-operated valves. The outer valve is normally de-energized and its breaker locked open when RCS pressure is greater than 450 psig. These valves are not subject to spurious actuation due to fire damage of control circuits. The only fire induced failure mechanism that could cause the outer valve to open would be a three-phase hot short of the motor operator power cable. If this failure occurred, the inner valve would still provide isolation. The occurrence of a three-phase hot short in conjunction with a hot short in a control cable, for separate valves on the same suction line, is not considered a credible event. Thus, the RCS integrity is assured at this interface following a fire. Under SPU conditions, there are no electrical changes, modifications or additions that will affect the current systems analysis.

Inadvertent ESF Signal Actuation Evaluation

The accident scenarios that require ESFAS automatic initiation are not postulated concurrent with a fire. However, inadvertent ESFAS actuation from fire-induced circuit faults could impact safe shutdown components, placing them in a position other than that required for safe shutdown. The signals that could affect the required safe shutdown components are identified in the BTP 9.5-1 Compliance Report. Instrument locations and cable routing was determined. Mitigating actions have been identified and included in the safe shutdown procedures. There are no electrical changes, additions or modifications resulting from the SPU that would impact the current analysis or safe shutdown procedures.

Loss of Offsite Power

A fire event coincident with a loss of offsite power is the limiting scenario and it represents a worst-case approach. For this reason, safe shutdown capability is maintained in the event of a fire occurring in any one fire area coincident with a loss of offsite power. This position is more limiting than any other scenarios where offsite power remains available. The SPU analyses were performed assuming a loss of offsite power.

Electrical Evaluation

A fire induced circuit failure analysis, including associated circuit concerns (i.e., breaker coordination, multiple high impedance faults, spurious actuations and common enclosures) is contained in the BTP 9.5-1 Compliance Report. The SPU impact on these areas was evaluated. For the hot short portion of the circuit failure analyses, offsite power is assumed to be available as it represents the worst case with respect to spurious operation of the equipment. Under SPU conditions, protection devices for safe shutdown equipment are not changed or modified so the current breaker coordination study is unaffected. There are no additional loads or wiring modifications that would increase the possibility of multiple high impedance faults. Apart from modifications required in support of the SPU, the SPU does not introduce additional cables, change, modify or add protective circuit devices or fire barriers. Therefore, the current analysis of circuit protective devices and fire rated barrier and penetration design remains valid. The impact of any plant changes in support of the SPU on the Safe Shutdown Evaluation are reviewed in accordance with the plant design change process and the existing NRC-approved Fire Protection Program.

2.5.1.4.2.3.5 Support Systems

The active support systems required for safe shutdown include the following:

- Emergency AC and DC distribution
- Diesel Generators
- Ventilation Systems (Control Building, Emergency Diesel Generator Room, ESF/Auxiliary Building, Circulating/Service Water Pumphouse, Containment)
- RCP seal cooling
- Instrument Air
- Emergency lighting
- Communications
- Process monitoring

The SPU does not introduce any new components or modify existing components that would affect the support systems required for safe shutdown following a fire. The current analysis of the support systems identified above remains valid under SPU conditions.

2.5.1.4.2.3.6 Resolution of Safe Shutdown Evaluation Problem Areas

Alternative Shutdown Capability

Alternative shutdown capability is provided for a fire in the Control Room, Cable Spreading Area, or the Instrument Rack Room. In evaluating the consequences of fires in the Control Room, Cable Spreading Room and Instrument Rack Room, it was determined that a control system was necessary to transfer signals from the affected areas to the Switchgear Rooms. The control system along with certain manual actions allows the plant to be brought to cold shutdown without using the Control Room, Cable Spreading Room, or Instrument Rack Room. Isolation, control and instrumentation for shutdown outside the Control Room is provided at the auxiliary shutdown panel (ASP), transfer switch panels A and B (TSPA and TSPB), fire transfer switch panel (FTSP), and the A train 4160 switchgear. Shutdown component control is transferred from the Control Room to the ASP by placing the transfer switches on TSPA and TSPB to the local position.

The SPU does not introduce any additional plant equipment failure modes that will impact the ability to achieve any of the alternative shutdown functions. The SPU does not affect the current alternative shutdown capability used to bring the plant to cold shutdown for a fire in the Control Room, Cable Spreading Room, or Instrument Rack Room.

Alternative shutdown methods are provided for performance of the following functions (methods briefly described within parentheses):

- Reactor coolant letdown (normal letdown path/reactor head vent)
- Auxiliary feedwater injection (motor-driven pumps/turbine-driven pump)
- Decay heat removal (atmospheric dump valves or atmospheric dump bypass valves/code safety valves)
- Boration (charging pumps from boric acid tank or RWST/high-head safety injection pump from RWST)
- RCS pressure control (auxiliary spray line/pressurizer power operated relief valves)

The SPU does not modify the current alternative shutdown methods used for safe shutdown, and does not require any new methods or equipment to perform the required alternative shutdown functions.

Long-Term Hot Shutdown

The auxiliary feedwater system supplies water to the secondary side of the steam generators to maintain a secondary heat sink for RCS heat removal. Currently, the credited on-site sources of auxiliary feedwater for safe shutdown following a fire are the DWST and condensate storage tank (CST); ultimately, the service water system is available to supply auxiliary feedwater via piping spool pieces. Analysis shows that, at SPU conditions, the combined DWST and CST volume is sufficient to maintain hot standby conditions for 28 hours, followed by a 5 hour cooldown to residual heat removal system initiation temperature (i.e., a total of 33 hours after reactor trip). The analyses that determine the time to cold shutdown following a fire at SPU conditions show that SG inventory makeup will be required beyond 33 hours after reactor trip for fires in certain fire areas, and therefore, additional sources of makeup are required. However, based on the deleterious effects of using service water in steam generators, service water will not be credited as the means of replenishing auxiliary feedwater for safe shutdown following a fire at SPU conditions. Instead, the DWST and CST will be replenished with makeup water from sources such as domestic water, demineralized water, and firewater (refer to Table 2.5.1.4-1). Service water will be used only as an option of last resort (i.e., not credited in the fire shutdown analysis). The proposed change will be based upon a defense-in-depth design approach for SG inventory beyond 33 hours after reactor trip. As a result of this change, changes to the MPS3 BTP 9.5-1 Compliance Report, procedures, and hardware may be required.

2.5.1.4.2.3.7 Operator Actions Required Following a Fire

Following a fire, equipment normally used to bring the plant to cold shutdown conditions may be inoperable. The operator actions identified in the BTP 9.5-1 Compliance Report summary of shutdown method by fire area serve as the technical bases for the EOP 3509 procedures. These procedures are written specifically for fire scenarios.

As addressed in Section 2.5.1.4.2.3.4, the operator actions and time limits associated with the limiting transients are not changed by the SPU. Therefore, the EOP 3509 procedures are unaffected by these limiting transients at SPU conditions.

The safe shutdown evaluation concluded that there is only one MPS3 fire area where major repairs may be required to achieve and maintain cold shutdown. A fire in the Auxiliary Building, elevation 24 ft 6 inch (Fire Area AB-1, North), could damage all three reactor plant component cooling water (CCP) system pumps. MPS3 has the capability to repair or replace one CCP pump motor using onsite material, and still achieve cold shutdown conditions within 72 hours after reactor trip using only onsite power (refer to Section 2.5.1.4.2.3.4). Maintenance procedure MP 3783EA, Component Cooling Pump Motor Replacement for Fire Protection, provides the instructions for replacing one CCP pump motor if a fire damages all three CCP pumps. The SPU does not affect this procedure.

As addressed in the FPER, no repairs are necessary to achieve hot standby or hot shutdown.

As addressed in the BTP 9.5-1 Compliance Report, in addition to the specific actions identified in the safe shutdown analysis, general information on the prioritization of the actions is also given. The Compliance Report notes that in the supplementary information presented in the promulgation of Appendix R, the NRC states in part: "…it is not possible to predict the specific conditions under which fires may occur and propagate." Based on that statement, it follows that it would not be possible to predict the exact behavior and interaction of plant systems, and thus manual operator actions were prioritized. One of the manual actions given high priority is the establishment of auxiliary feedwater to a minimum of two SGs. An analysis was performed to determine the steam generator dryout time at the SPU power level; the results showed a dryout time of approximately 37 minutes. Therefore, there continues to be adequate time for the operator to manually initiate auxiliary feedwater to the SGs at SPU conditions.

A fire in the Containment (fire area RC-1) requires local manual operation inside containment to change the position of the four Safety Injection Tank (SIT) isolation valves and two of the 'B" train RHR suction valves. For the current conditions, an evaluation was performed to assure that the environmental conditions will allow Containment entry to perform these valve manipulations. The assessment was based upon the radiological doses due to airborne sources and the expected containment temperature. The current evaluation concluded that the radiological conditions from the postulated airborne sources will allow Containment entry. However, the Containment temperature will exceed the threshold for requiring heat stress countermeasures for the operators entering Containment.

The current analysis has been reviewed for impact due to SPU conditions. While the estimated steam releases inside containment are independent of SPU conditions, additional conservatisms have been taken to ensure the mass releases are bounding. Assuming a flashing fraction of 0.39, the updated steam releases are bounded by the currently assumed steam releases. This will offset the modest increase (less than 7 percent) in the expected radioactive airborne concentrations due to the SPU.

At SPU conditions, the Containment temperature will continue requiring heat stress countermeasures.

Thus, it is concluded that the SPU conditions will not change the conclusions of the current evaluations determining the capability for Containment entry.

It should be noted that there are issues associated with the current analysis for the Containment fire that are under evaluation under the Millstone 3 Corrective Action program (CR-07-06257). These issues are unrelated to SPU parameters and the resolution would be unaffected by SPU conditions. The time frame for resolution of these issues is controlled by the Corrective Action process and is expected to be resolved prior to implementation of the SPU.

Similarly, operator actions inside Containment are required for the fire in the North Residual Heat Removal (RHR) Heat Exchanger Cubicle (fire area ESF-3). The evaluation of the operator actions inside Containment for this scenario is bounded by the Containment fire scenario discussed above.

2.5.1.4.2.3.8 Other Supporting Analyses/Evaluations

The SPU impact on the following analyses is discussed below:

- Temporary ventilation for CCP pumps due to fire
- Risk/potential for radiological release due to a fire

Temporary Ventilation for CCP Pumps Due to Fire

Temporary ventilation is provided for the CCP pumps area in the event of loss of the primary ventilation system due to a fire. An analysis at current conditions concluded that, given a 115°F CCP heat exchanger outlet temperature during plant cooldown with single train operation, the heat load for the CCP pump area temporary ventilation system is less than the design load and the area temperature remains within design limits. An analysis shows that, following a fire with single train operation at SPU conditions, the CCP heat exchanger outlet temperature remains less than 110°F during plant cooldown. Therefore, since the CCP heat exchanger outlet temperature in the current analysis bounds the CCP heat exchanger outlet temperature at SPU conditions, the area temperature will remain within design limits at SPU conditions.

Risk/Potential for Radiological Release Due to a Fire

A qualitative assessment was performed to determine the SPU impact on the Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) due to a fire. At SPU conditions, electrical components will continue to operate within their design capacity such that there is no substantial increase in the likelihood of an electrical component failure causing a fire. The SPU will not require any significant increase in combustible material volume. Thus, it is concluded that the SPU will have no significant impact on the likelihood of a fire. There are no changes in the mitigation strategy for any postulated fire scenarios as a result of the SPU. Since operator requirements have not changed, it is concluded that the SPU has no impact on the likelihood of operators failing to mitigate a fire scenario as expected. There is no impact on the likelihood of failure to mitigate a postulated fire scenario. Based on the qualitative assessment, there is no significant increase in the potential for a radiological release from a fire at SPU conditions.

2.5.1.4.3 Conclusion

DNC has reviewed the fire-related safe shutdown assessment and concludes that the assessment adequately accounted for the effects of increased decay heat on the ability of the required systems to achieve and maintain safe shutdown conditions. Based on this, DNC concludes that the Fire Protection Program will continue to meet the requirements of 10 CFR 50.48 and Branch Technical Position CMEB 9.5-1, and the MPS3 current licensing basis with respect to the requirements of GDC-3 and GDC-5. Therefore, DNC finds the proposed SPU acceptable with respect to fire protection.

Table 2.5.1.4-1
Fire Shutdown and Long-Term SG Inventory Makeup Required To Support The Decay Heat Removal Design Function BTP 9.5-1 Deviation Request – Sections c.5.c.3 and c.5.c.5

Standard Review Plan 9.5-1 Fire Protection Rev 2, July 1981

Section c.5.c.3 states

"The shutdown capability for specific fire areas may be unique for each such area, or it may be one unique combination of systems for all such areas. In either case, the alternative shutdown capability shall be independent of the specific fire area(s) and shall accommodate postfire conditions where offsite power is available and where offsite power is not available for 72 hours. Procedures shall be in effect to implement this capability."

Section c.5.c.5 states

"Equipment and systems comprising the means to achieve and maintain cold shutdown conditions should not be damaged by fire; or the fire damage to such equipment and systems should be limited so that the systems can be made operable and cold shutdown achieved within 72 hours. Materials for such repairs shall be readily available onsite and procedures shall be in effect to implement such repairs. If such equipment and systems used prior to 72 hours after the fire will not be capable of being powered by both onsite and offsite electric power systems because of fire damage, an independent onsite power system should be provided. Equipment and systems used after 72 hours may be powered by offsite power only."

Deviation Request

DNC proposes an alternate fire shutdown design approach for long-term steam generator (SG) inventory makeup based upon defense-in-depth design features and risk informed insights.

BTP CMEB 9.5-1 (Rev. 2, July 1981), Section c.5.c.3 and c.5.c.5 define regulatory positions for alternative and dedicated shutdown capability. This deviation request is associated with both alternative and dedicated shutdown capability. These regulatory positions infer a deterministic fire shutdown analysis requirement that accommodates post-fire conditions where offsite power is unavailable for 72-hours. An alternate fire shutdown design approach based upon a defense-in-depth design features is proposed as an alternative (for DWST or CST long-term replenishment, if needed).

BTP CMEB 9.5-1 (Rev. 2, July 1981), Section 6.b defines regulatory positions applicable to the fire protection water system. The proposed alternate fire shutdown design approach lists the fire protection water system as one of the available options to refill the DWST in the long term. We have not identified any deviation associated with listing the fire water systems as an available post-fire option to replenish the DWST/CST in the long-term.

Reason

Westinghouse Technical Bulletin NSID-TB-89-02 has advised against using seawater as a long-term SG makeup source because a new Westinghouse evaluation had changed the safety perspective concerning steam generator tube integrity. Specifically, this fission product release barrier could experience through wall failures in 24-hours after seawater introduction due to adverse material interactions.

Stretch power uprate increases the long-term inventory SG makeup requirements, increases SG seawater introduction and exacerbates the SG tube integrity issue. Therefore, DNC is proposing a fire shutdown design approach that does not rely upon seawater introduction into the SG's.

Table 2.5.1.4-1
Fire Shutdown and Long-Term SG Inventory Makeup Required
To Support The Decay Heat Removal Design Function
BTP 9.5-1 Deviation Request – Sections c.5.c.3 and c.5.c.5

Current Design and Licensing Bases

The auxiliary feedwater (AFW) system includes a Demineralized Water Storage Tank (DWST), which is the safety related storage tank. The AFW System has cross-connect design features that allow the AFW pumps to be aligned to the condensate storage tank (CST) or the service water system (seawater). The CST has a 300,000-gallon capacity and inventory is normally maintained above 210,000 gallons. The current fire shutdown design is based upon a combined DWST and CST usable inventory that allows for 38-hours of hot standby operation, followed by a 5-hours cooldown to RHR entry conditions (38 + 5 = 43-hours). Service water is credit for additional long-term SG makeup, as necessary, to support obtaining a cold shutdown condition.

Administrative Controls - T/S 3.7.1.3 ensures that there is at least a 334,000 gallon measured volume in the DWST (approximately 16-hours under natural circulation conditions). Normally, there are no administrative controls in effect for minimum required CST volume.

Proposed Design and Licensing Bases

DNC proposes a fire shutdown design that is based upon:

- A DWST 334,000-gallon measured tank inventory consistent with T/S 3.7.1.3. This corresponds to 13-hours of SG inventory makeup under natural circulation conditions with the decay heat load after SPU.
- The CST providing 210,000-gallons additional SG-makeup. This combined DWST and CST inventory provides 33-hours of makeup water with the decay heat load after SPU. No fire shutdown administrative controls are proposed for the CST level.
- The availability of a diverse DWST or CST refill capability that ensures a highly reliable SG-makeup capability, if needed for fires with extensive fire damage that causes RHR entry to extend beyond 33-hours after reactor trip.

Table 2.5.1.4-1
Fire Shutdown and Long-Term SG Inventory Makeup Required
To Support The Decay Heat Removal Design Function
BTP 9.5-1 Deviation Request – Sections c.5.c.3 and c.5.c.5

Additional Supporting Information

- The above proposed fire shutdown decay heat removal design approach is not dependent upon the availability of off-site power for the first 33-hours after reactor trip.
- In the likely situation where normal electrical power is available after 33-hours after reactor trip and the unlikely situation that there is extensive fire damage such that RHR entry times are delayed, there are diverse methods for making up to the DWST and CST such that there is high confidence that this support function can be accomplished. The diverse DWST and CST tank makeup options includes:
  - An existing tank refill capability from the water treating facility with an adequate makeup capacity.
  - An existing DWST to domestic water cross-tie design feature, with an adequate makeup capacity.
  - Other tank makeup options, including the options listed below.
- In the unlikely situation that the above options are unavailable due to sustained electrical power unavailability and the unlikely situation worst case fire damage exist and RHR entry times are delayed due to extensive fire damage; DWST or CST refill can be accomplished by:
  - The fire water system can be used to transfer water into the DWST. The fire water system design features include a diesel driven pump.
  - A portable diesel driven pump that is available for this DWST refill purpose and is associated with the B.5.b security order response. This DWST refill option includes pre-staged fittings necessary to connect to the DWST. These fittings are currently maintained in the fire shutdown equipment storage location. The security event diesel driven pump capacity is significantly greater than required for the fire shutdown event.
  - No fire shutdown administrative controls are proposed for this diesel driven pump. The availability of this diesel driven pump will be controlled under our B.5.b security program. Procedural guidance for tank refill will be associated with our B.5.b security program. It is expected that there will be times when this pump may not be located at its normal storage location due to maintenance or security event training activities.
  - DWST and CST refill can be accomplished by other means.

Justification

The proposed fire shutdown change improves the reliability of a fission product barrier (i.e., steam generator tube integrity). Relative to the reliability of the decay heat removal design function during a fire event, there is negligible impact on the risk of radiological releases to the environment due to a fire. The proposed change complies with 10 CFR 50.48 & GDC-3 requirements.

Table 2.5.1.4-1
Fire Shutdown and Long-Term SG Inventory Makeup Required
To Support The Decay Heat Removal Design Function
BTP 9.5-1 Deviation Request – Sections c.5.c.3 and c.5.c.5

Summary

An alternate fire protection design approach is proposed to support the long-term decay heat removal design function based upon a defense-in-depth design approach. This alternate design approach satisfies 10 CFR 50.48 & GDC-3 requirements. The proposed design approach poses no increased risk of a radiological release to the environment.

2.5.2 Pressurizer Relief Tank

2.5.2.1 Regulatory Evaluation

The Pressurizer Relief Tank (PRT) is a pressure vessel provided to condense and cool the discharge from the pressurizer safety and relief valves. The tank is designed with a capacity to absorb discharge fluid from the pressurizer relief valve during a specified step-load decrease. The PRT system is not safety-related and is not designed to accept a continuous discharge from the pressurizer. DNC reviewed the PRT to ensure that operation of the tank is consistent with transient analyses of related systems at the SPU power level and that failure or malfunction of the PRT system will not adversely impact safety-related SSCs.

The DNC review focused on any design changes related to the PRT and connected piping, and changes related to operational assumptions that are necessary in support of the proposed SPU that are not bounded by previous analyses.

The review ensured that:

- The steam condensing capacity of the tank and the tank rupture disc relief capacity are adequate, taking into consideration the capacity of the pressurizer power-operated relief and safety valves
- The piping to the tank is adequately sized
- Systems inside containment are adequately protected from the effects of high-energy line breaks and moderate-energy line cracks in the pressurizer relief system

The acceptance criteria for this review are:

- GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes
- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate and be compatible with specified environmental conditions, and be appropriately protected against dynamic effects, including the effects of missiles.

Specific review criteria are contained in the SRP, Section 5.4.11, and guidance provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800 “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants,” July 1981, SRP Section 5.4.11, Rev. 2. As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A as amended through October 27, 1978. The adequacy of the MPS3 design relative to the GDC is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 pressurizer relief tank regarding conformance to the following:

- GDC-2 is described in FSAR Section 3.1.2.2, Design Bases for Protection Against Natural Phenomena (Criterion 2).

  Those features of plant facilities that are essential either to the prevention of accidents that could affect the public health and safety or to the mitigation of accident consequences are designed to:

  1. Quality standards that reflect the importance of the function to be performed. Approved design codes are used when appropriate to the nuclear application.

  2. Performance standards that enable the facility to withstand, without loss of the capability to protect the public, the additional forces imposed by the most severe earthquake, flooding condition, wind, ice, or other natural phenomena for the site, as well as credible combinations of the effects of normal and accident conditions with the effects of the natural phenomena.

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4).

  SSCs important to safety are designed in accordance with the codes and classifications to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

  SSCs important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in the FSAR Section 3.2.5. FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the SSCs important to safety are designed.

The PRT system is described in FSAR Section 5.4.11.

In addition to the evaluations described above, the RCS components were evaluated for continued acceptability to support plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. NUREG-1838 Sections 2.3B.1.3.1 and 3.1B are applicable to the PRT.

2.5.2.2 Technical Evaluation

2.5.2.2.1 Introduction

The PRT is described in FSAR Section 5.4.11. The PRT collects, condenses, and cools steam and water discharged from various safety and relief valves within containment and directs the fluid to the waste processing system. The PRT can also be used for venting the reactor vessel head. Principal PRT design parameters are provided in FSAR Table 5.4-13. A PRT diagram is shown in FSAR Figure 5.4-7.

The pressurizer safety valves and pressurizer PORVs discharge to the PRT through a submerged sparger pipe. The PRT is normally filled with water at or near ambient containment conditions. The water condenses and cools the discharged steam. The tank is also equipped with an internal spray and a drain that are used to cool the water following a discharge. A nitrogen atmosphere is maintained to allow room for the expansion of the original water volume plus the condensed steam discharge. The tank size is based on the design requirements to condense and cool a discharge equivalent to 110 percent of the full-power pressurizer steam space. This sizing basis was selected to ensure the tank could accept the discharge from the pressurizer safety valves following the worst-case loss of external load transient without the resulting reactor trip (Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum). The PRT is constructed of austenitic stainless steel and is overpressure protected in accordance with ASME Code Section VIII, Division 1, by two safety heads with stainless steel rupture discs.

2.5.2.2.2 Description of Analyses and Evaluations

The PRT was evaluated to ensure that the tank was capable of performing its intended function for the range of NSSS design parameters approved for the SPU (Section 1.1, Table 1-1). The evaluation was conservatively performed for an analyzed NSSS thermal power of 3666 MWt.

The pressurizer safety valves require an adequate capacity to ensure that the RCS pressure does not exceed 110 percent of system design pressure. This is the maximum pressure allowed by the ASME Code, Section III, NB-7300 and NC-7300. RCS design pressure has not changed for the SPU. Based on the range of NSSS design parameters for the SPU, an analysis of the loss of external electrical load transient was performed. The analysis results confirmed that the installed pressurizer safety valves capacity is adequate to preclude RCS over-pressurization (Section 2.8.5.1.2, Loss of External Electrical Load, Turbine Trip and Loss of Condenser Vacuum). Based on the analysis results, the pressurizer surge line, safety valve inlet piping, and safety valve discharge piping (including the PRT sparger pipe) designs are also adequate, since they are based on safety valve design capacity.

The PRT design is based on the total safety valve capacity and conservatively sized to condense and cool a steam discharge equal to 110 percent of the full power pressurizer steam volume. The amount of energy absorbed by the PRT is related to the volume and pressure of the discharged steam. The loss of external electrical load transient analysis determined that the pressurizer steam mass and energy discharged into the PRT is less than the design bases discharge; the PRT design remains conservative (Reference 1).

The PORVs are required to have adequate capacity to prevent a pressurizer high- pressure reactor trip for an external load reduction of up to 50 percent of rated electrical load. Based on the range of NSSS design parameters for the SPU, a margin to trip analysis was performed. The results of this analysis (Section 2.4.3, Pressurizer Component Sizing) confirmed that the installed PORVs capacity is adequate to preclude a pressurizer high- pressure reactor trip. Based on these results, the PORVs inlet and discharge piping design is adequate, since the piping design is based on the PORVs design capacity. The mass and energy addition to the PRT during load rejection is not limiting with respect to the PRT design, since this transient discharge is less severe than the loss of external electrical load/ turbine trip transient discharge (Reference 1).

The PRT high and low level alarm set points ensure adequate coolant is maintained in the tank to condense and cool the design bases discharge, and to prevent the PRT temperature and pressure from exceeding the design limits of 200°F and 50 psig respectively. The loss of external electrical load analysis addressed the full range of SPU NSSS design parameters and changed the pressurizer level program band upper value from 61 percent to 64 percent. This change resulted in a re-evaluation of the existing PRT high and low level alarms setpoints. Revised level alarm setpoints were necessary for the PRT to accept a 110 percent of the pressurizer steam space discharge at the SPU pressurizer level. Revised PRT high and low level alarm setpoints are 84 percent and 56 percent respectively.

Since the SPU does not impact the PRT function and operation, the current design basis for PRT interface support functions is also not impacted. These support functions include primary grade water makeup for cooling, nitrogen for pressure control, gas analyzer connection for periodic sampling, and PRT vent and drain.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for the PRT. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating the PRT at SPU conditions does not add any new or previously unevaluated materials. PRT internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.2.2.3 Results

The current PRT design basis bounds the SPU loss of external load analysis mass and energy addition, such that the PRT continues to meet its design basis mass and energy addition. The revised PRT high and low level alarm setpoints were calculated at 84 percent and 56 percent respectively.

2.5.2.2.4 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the PRT. DNC concludes that the evaluation adequately accounted for the effects of the proposed SPU on the ability of the PRT to maintain its design functions, and will meet MPS3 current licensing basis with respect to the requirements of GDC-2 and GDC-4. Therefore, DNC finds the proposed SPU acceptable with respect to the PRT design.

2.5.3 Fission Product Control

2.5.3.1 Fission Product Control Systems and Structures

2.5.3.1.1 Regulatory Evaluation

The DNC review for fission product control systems and structures covered the basis for developing the mathematical model for design basis LOCA dose computations, the values of key parameters, the applicability of important modeling assumptions, and the functional capability of ventilation systems used to control fission product releases. The DNC review primarily focused on any adverse effects that the SPU may have on the assumptions used in the analyses for the control of fission products. The acceptance criteria for this review are

- GDC-41, insofar as it relates to the containment atmosphere cleanup system to be provided to reduce the concentration of fission products released to the environment following postulated accidents.

Specific review criteria are contained in SRP Section 6.5.3 and guidance provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, SRP 6.5.3, Rev. 2, July 1981.

As noted in the FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. the adequacy of the MPS3 design relative to the design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to

- GDC-41, Containment Atmosphere Cleanup, is described in FSAR Section 3.1.2.41:

  The SLCRS collects radioactive leakage from the containment to the containment enclosure and contiguous areas following a LOCA (FSAR Section 6.2.3.2).

  The QSS sprays borated water into the containment atmosphere to reduce the containment pressure. The pH in the containment sumps is controlled by the dissolution of trisodium phosphate (stored in baskets) in the sump water (FSAR Section 6.2.2).

  These systems are sufficiently redundant to perform their safety function assuming a single active failure in the short term or a single active or passive failure in the long term and are operable with either onsite or offsite power.

On September 15, 2006, the NRC approved DNC's license amendment request regarding full-scope implementation of the alternate source term for MPS3 and issued Amendment No. 232 to the MPS3 Operating License. FSAR Section 15.6.5.4 was revised to incorporate the radiological consequence analysis utilizing the alternate source term methodology. This analysis credits the use of the QSS and RSS for containment airborne iodine removal. FSAR Table 15.6-9 identifies the assumptions utilized to determine the radiological consequences associated with a

LOCA. It defines the time periods that the QSS and RSS are credited to remove airborne iodine. Although the RSS continues to operate after QSS stops, no credit was taken for airborne iodine removal by the RSS after operation of the QSS stops. In addition, a timer was utilized to actuate the RSS pumps after receipt of a containment depressurization actuation signal.

In a letter dated September 13, 2005, and supplemented by letters dated June 13 and August 14, 2006, DNC proposed a change to the Technical Specifications to resolve GSI 191, Assessment of Debris Accumulation on Pressurized Water Reactor Sump Performance. This license amendment request proposed to change the method for starting the RSS. Instead of utilizing a timer to actuate the RSS pumps after receipt of a CDA signal, DNC proposed to start the RSS pumps on receipt of a RWST low-low level signal after receipt of a CDA signal. This results in a delay of the RSS pump start time (from 780 seconds to 2450 seconds) and a change to the effective time of RSS spray coverage (from 840 seconds to 2710 seconds). As a result, the radiological consequence analysis associated with the LOCA was revised. In the revised analysis, DNC proposed to credit the RSS for airborne iodine removal from the time that the system becomes effective through the end of the transient (30 days). The NRC approved the license amendment request on September 20, 2006. DNC implemented the License Amendment provisions associated with the RSS during the 2007 spring outage for MPS3.

The QSS consists of two parallel flow paths that provide quench spray from opposite sides of the two spray headers. Each flow path consists of one spray pump and associated piping and valves that draw water independently from the RWST. The QSS pumps start on a CDA signal. The QSS is capable of operating continuously until the RWST is nearly emptied (nominal QSS auto-trip level). Each QSS pump is capable of supplying approximately 4,000 gallons per minute of borated water solution to the two 360° QSS headers, with a spray effectiveness consistent with the accident analysis assumptions. The system meets the redundancy requirements of an engineered safety feature and will satisfy the system performance requirements despite the most limiting single-active failure in the short term or the most limiting single-active or passive failure in the long term. (FSAR Sections 6.2.2.2 and 6.5.2.2)

Each of the two RSS subsystems consists of two containment recirculation coolers and pumps that share two spray headers with a spray effectiveness consistent with the accident analyses. The four RSS pumps take suction from a common containment sump and provide cooled flow to containment recirculation, safety injection, and charging. Following receipt of a CDA signal, each RSS pump starts automatically when the level in the RWST reaches the low-low level setpoint. Two risers feed each RSS spray header, with each riser running from one of the RSS coolers in each of the subsystems. The two pumps in each subsystem are connected to different spray headers, but they are both connected to the same emergency bus. Failure of one emergency bus does not prevent delivery of sufficient containment recirculation flow. The design of the containment recirculation system is sufficiently independent and redundant so that an active failure in the recirculation spray mode, cold leg recirculation mode, or hot leg recirculation mode of the ECCS has no effect on its ability to perform its engineered safety function. (FSAR Section 6.2.2.2)

Rising sump water due to a LOCA will dissolve TSP stored in twelve porous baskets located on Elevation (-)24'-6" of the Containment structure. The amount of TSP is sufficient to raise the final pH of the containment sump water to above 7.0, considering the maximum total volume of borated water that could become available in the sump following a LOCA. The dissolving characteristics of the TSP assure its dissolution at a rate equal or faster than the rate of its submergence in the rising water. The mixing action of the RSS pumps assures evenly distributed pH throughout the flooded and sprayed areas. (FSAR Section 6.2.2.2)

The minimum expected ultimate sump pH as 7.0 in FSAR Table 6.1-2. FSAR Figure 6.5-1 establishes the minimum containment sump pH following a LOCA. It shows that the containment sump pH will be greater than 7.0 for the entire period that the RSS pumps are assumed to operate post-LOCA. Per the DNC letter dated September 13, 2005, the RSS pumps are assumed to start at 2530 seconds post-LOCA, and are effective from 2710 seconds post-LOCA to 30 days post-LOCA.

Following a DBA, the secondary containment is maintained under negative pressure with the use of the SLCRS (FSAR Section 6.2.3). The secondary containment at MPS3 consists of a Containment enclosure structure and contiguous buildings. The SLCRS collects radioactive leakage from the Containment to the Containment enclosure and contiguous areas following a DBA. The SLCRS exhausts the air from these areas, filtering and removing particulate and gaseous iodine from the air, before discharging to the outside atmosphere via the Millstone Stack.

The SLCRS consist of two exhaust fans, each supplied from a separate emergency bus, two filter banks, and associated ductwork and dampers. Each filter bank includes a moisture separator, electric heater, upstream HEPA filter, a charcoal adsorber, and downstream HEPA filter. SLCRS in conjunction with the auxiliary building filter system function is, to drawdown enclosures contiguous to the Containment to a minimum negative pressure within the time frame assumed in the accident analysis. (FSAR Section 6.2.3.2)

The Containment structure enclosure is evacuated by the SLCRS to a slightly negative pressure after the accident. This ensures the leakage from the primary containment is passed through the high-efficiency particulate air (99 percent efficient) filters of the SLCRS prior to release from the enclosures contiguous to the Containment. This filtration will ensure a reduction of effective primary leakage released to the environment. (FSAR Sections 6.2.3.2 and 6.2.6.5)

The drawdown flow capacity of each redundant SLCRS filter train with free inlet conditions, i.e., with SLCRS boundaries not isolated in a safety injection mode of operation, exceeds the design leakage rate across the boundaries of the building with a differential pressure across the boundaries. (FSAR Section 6.2.3.3)

The QSS, RSS, and SLCRS were evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838 Sections: 1) 2.3B.2.2 and 3.2B.2.3.2 are applicable to the QSS; 2) 2.3B.2.1 and 3.2B.2.3.1 are applicable to the RSS; and 3) 2.3B.3.35 and 3.2B.2.3.33 are applicable to the SLCRS; and 4) 2.3B.2.1 is applicable to containment recirculation system, which includes the sump (TSP).

2.5.3.1.2 Technical Evaluation

QSS, RSS, and SLCRS

Section 2.9.2 discusses the impacts of the SPU on the analysis of the radiological consequences associated with the LOCA. The changes in assumptions regarding the operation of the QSS and RSS system are identified and justified in that section. The revised radiological consequences analysis regarding the LOCA demonstrates the effectiveness of the QSS, RSS, and SLCRS to minimize the release of radioactivity to the environment following a DBA by establishing that the post-LOCA doses are within the applicable acceptance criteria.

Containment Sump pH

In Section 2.6.5, DNC has analyzed the impact of SPU on the post-LOCA sump water pH. The containment sump pH was determined to remain above 7.0 for the entire period that the RSS is assumed to operate. The ultimate containment sump pH at 30 days post-LOCA (ultimate sump pH) was determined to be 7.05.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the fission product control systems are within the scope of License Renewal. Aging management programs are addressed in the License Renewal SER Sections 3.2B.2.3.1, 3.2.B.2.3.2, and 3.3B.2.3.33 for the containment recirculation system, RSS, QSS, and SLCRS, respectively. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating at SPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.3.1.3 Results

Section 2.9.2 discusses the impacts of the SPU on the LOCA radiological consequences analysis. It includes changes to the assumptions regarding QSS and RSS operation. The calculation concludes that the control room and off-site doses due to the LOCA remain within the applicable regulatory criteria. Therefore, the QSS, RSS, and SLCRS, in conjunction with other structures, systems, and components, remain effective in limiting the doses to the control room and off-site individuals.

In addition, as discussed in Section 2.6.5, DNC has confirmed that the containment sump pH will remain above 7.0 for the entire period of time that the RSS is assumed to operate, and that the ultimate containment sump pH will be greater than 7.0.

2.5.3.1.4 Conclusion

DNC has performed an assessment of the effects of the proposed SPU on fission product control systems and structures. DNC has adequately accounted for the increase in fission products and changes in expected environmental conditions that would result from the proposed SPU. DNC further concludes that the fission product control systems and structures will continue to provide adequate fission product removal in post-accident environments following implementation of the proposed SPU. Based on this, DNC also concludes that the fission product control systems and structures will continue to meet the current licensing basis with respect to the requirements of GDC-41. Therefore, DNC finds the proposed SPU acceptable with respect to the fission product control systems and structures.

2.5.3.1.5 References

1. DNC letter to the NRC, “Millstone Power Station Unit 3, Proposed Technical Specification Changes, Recirculation Spray System,” dated September 13, 2005.

2. DNC letter to the NRC, “Millstone Power Station Unit 3, Proposed Technical Specification Changes, Recirculation Spray System,” dated June 13, 2006.

3. DNC letter to the NRC, “Millstone Power Station Unit 3, Proposed Technical Specification Changes, Recirculation Spray System,” dated August 14, 2006.

4. NRC letter to DNC, “Millstone Power Station Unit No. 3 – Issuance of Amendment Re: Recirculation Spray System (TAC NO. MC8327),” dated September 20, 2006.

5. NRC Letter to DNC, “Millstone Power Station Unit No. 3 – Issuance of Amendment Re: Alternate Source Term (TAC NO. MC3333),” dated September 15, 2006.

6. Regulatory Guide 1.183, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors.

2.5.3.2 Main Condenser Evacuation Systems

2.5.3.2.1 Regulatory Evaluation

The main condenser evacuation system (ARC) consists of two subsystems:

- The condenser air removal and priming ejectors (hoggers) that initially establish main condenser vacuum.
- The condenser air removal steam jet air ejectors to maintain condenser vacuum once it has been established.

The DNC main condenser evacuation review focused on the effects of the proposed SPU on the system's capability to maintain condenser vacuum, changes that may affect gaseous radioactive material handling and release assumptions, and design features to preclude the possibility of an explosion (if the potential for explosive mixtures exists).

The acceptance criteria for this review are:

- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive materials in effluents to the environment.
- GDC-64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences and postulated accidents

Specific review criteria are contained in SRP Section 10.4.2 and guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 10.4.2, Rev 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 Station design relative to conformance to:

- GDC-60 is described in the FSAR Section 3.1.2.60, Control of Releases of Radioactive Materials to the Environment (Criterion 60)

  As described in this FSAR section, in all cases the design for radioactivity control is based on:

  - The requirements of 10 CFR 20, 10 CFR 50, and 10 CFR 50, Appendix I, for normal operations and for any transient situation that might reasonably be anticipated to occur.
  - 10 CFR 50.67 dose level guidelines for potential accidents of extremely low probability of occurrence.

All releases paths, including ventilation and process streams are monitored and controlled as described in FSAR Section 11.5, Process, Effluent and Airborne Radiation Monitoring Systems.

Radioactive gaseous waste effluent activity levels are monitored subsequent to release through the Millstone 375 foot stack. Under conditions of concurrent fuel failure and steam generator tube leakage, radioactive gas, if present, will be suitably controlled in the steam jet air ejector discharge in the ARC system.

- GDC-64 as described in the FSAR Section 3.1.2.64, Monitoring Radioactive Releases (Criterion 64).

  Normal unit effluent discharge paths are monitored during normal plant operation by ventilation particulate samples and gas monitors in the auxiliary building and engineered safety buildings (FSAR Section 11.5). After a postulated accident the safety-related ventilation vent monitors and the safety-related supplemental leak collection and release system monitors are used to monitor the effluents from spaces contiguous to the containment structure. Radioactivity levels in the environs are controlled during normal and accident conditions by various radiation monitoring systems described in FSAR Section 11.5, Process, Effluent and Airborne Radiation Monitoring Systems and FSAR Section 12.3.4, Area Radiation and Airborne Radioactivity Monitoring, and monitored by the collection of samples as part of the offsite radiological monitoring program.

Additional details that define the licensing basis are described in FSAR Section 10.4.2, Main Condenser Evacuation System. The ARC is designed to draw the initial vacuum in the condenser shells during startup, maintains vacuum during operation and dispose of noncondensible gases from the condenser. The condenser evacuation system is nonsafety-related. The ARC is designed in accordance with GDC-60 and -64 with the provisions for control and monitoring the release of radioactivity to the environment.

As addressed in MPS3 Safety Evaluation Report (NUREG-1031, August 2, 1984), Section 10.4.2, “Main Condenser Evacuation System’s Compliance with GDC-60 and -64”, MPS3 has met the requirements of GDC-60 and -64 and Heat Exchanger Institute Standard, “Standard for Steam Surface Condensers”. The main condenser evacuation system can establish and maintain main condenser vacuum by removing noncondensible gases from the main condenser. Air and noncondensible gases removed from the main condenser shell by the steam jet air ejectors are continuously monitored for radioactivity and discharged through the plant stack.

The air and noncondensible gases removed by air removal mechanical vacuum pumps are directly discharged to the atmosphere through a vent stack in the condensate polishing enclosure. MPS3 has taken an exception to SRP 11.5 by not monitoring airborne noble gas radioactivity in the exhaust from the main condenser air removal vacuum pumps. Instead, MPS3 monitors the noble gas by a calculational method based on noble gas activity measured at the main condenser air ejector monitor.

In addition to the evaluations described above, selected MPS3 systems were evaluated for the continued acceptability for the purpose of plant license renewal. The results of that review are found in NUREG-1838, Safety Evaluation Report Related to License Renewal Millstone Power

Station, Unit 2 and 3, dated August 1, 2005. The condenser air removal system is not within the scope of license renewal.

2.5.3.2.2 Technical Evaluation

2.5.3.2.2.1 Introduction

The condenser air removal system is described in the FSAR Section 10.4.2. The condenser air removal system removes non-condensable gases from the condenser to draw a vacuum for start up and then to help maintain condenser vacuum during operation. The air removal system consists of two triple-element first-stage and single-element second-stage steam air ejectors and two horizontal, motor driven rotary-wing pumps. The three condenser shells share a common connection to the pumps. The two motor driven pumps are provided to create vacuum at startup.

2.5.3.2.2.2 Description of Analyses and Evaluations

The condenser air removal system must be capable of removing non-condensable gases and air in-leakage from the condenser shell (steam space) to maintain vacuum. Air in-leakage will not be affected by the SPU since it is entirely due to the physical design of the condenser and its state of degradation. In addition, any existing air in-leakage may be slightly reduced due to the higher condenser backpressure at SPU. Therefore, the air removal system is evaluated by comparing its removal capability with the expected increase in non-condensibles resulting from the increased low pressure turbine exhaust flow rate at SPU conditions. Refer to Section 2.5.5.2, Main Condenser for additional discussion related to the condenser.

The steam jet air ejector capacity/evacuation rate provided from the HEI standards required for the SPU steam flow rate is bounded by the design capacity of the steam jet air ejectors. Therefore, the existing steam jet air ejectors are adequate for SPU without modifications.

FSAR Table 11.3-1 indicates expected annual radioactivity releases to the atmosphere from MPS3, including the mechanical condenser air removal pumps exhaust. These values were determined using the guidance from NUREG-0017. Four years of monitoring (1986-1989) showed that the mechanical condenser air removal pumps exhaust did not contribute to any measurable radioactivity releases. Based on these results, the calculational methodology for the mechanical condenser air removal pumps exhaust radioactivity monitoring implemented in 1985 was eliminated. DNC completed calculation 06-ENG-04218R3, “Impact of SPU on Normal Operation Radiological Gaseous and Liquid Effluents at MPS3,” to determine if any significant changes would result from the SPU implementation.

Current plant design relative to conformance to GDC-60 and GDC-64 is not impacted by SPU. For gaseous radioactive material handling refer to Section 2.5.6.1, Gaseous Waste Management Systems.

Evaluation of the design features necessary to preclude the possibility of an explosion revealed there is no potential for explosive mixtures in the condenser at SPU conditions based on the venting capacity of the existing steam jet air ejectors, which bounds HEI required design capacity.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above in Section 2.5.3.2.1, the main condenser evacuation system is not within the scope of license renewal. However, the changes associated with operating the main condenser evacuation system at SPU conditions do not add any new or previously unevaluated materials to the system or exceed the operating or environmental parameters previously evaluated for equipment included within the scope of the rule. Thus, no new aging effects requiring management are identified.

2.5.3.2.2.3 Results

Current steam jet air ejector capacity of 90 SCFM satisfies the recommended removal capacity of the Heat Exchange Institute Standards for Steam Surface Condensers for a steam flow range of 2,000,000 to 3,000,000 lb/hr (45 SCFM). As the predicted SPU steam flow of 2,844,437 lb/hr is within this steam flow range, the current steam jet air ejector capacity is acceptable for the proposed SPU.

The two motor-driven vacuum pumps are provided to evacuate non-condensable gases from the condenser during MPS3 startup. Since startup conditions do not change due to SPU operation, the motor-driven vacuum pumps are adequate at SPU conditions.

The design of the main condenser evacuation system does not change following the implementation of SPU. Therefore, the SPU does not impact MPS3 regarding the control of radioactive material or the monitoring of releases in accordance with GDC-60 and GDC-64, respectively. For discussion related to the impact of SPU on radiological effluent releases from the MPS3 Station and compliance with 10 CFR 50, Appendix I, refer to Section 2.10.1, Occupational and Public Radiation Doses.

2.5.3.2.2.4 Conclusion

The evaluation concluded that the main condenser evacuation system will maintain its ability to remove non-condensable gases from the condenser during start up and normal operation without modifications. The review concluded that the main condenser evacuation system will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment following implementation of the SPU. Refer to Section 2.10.1, Occupational and Public Radiation Doses for discussion of the adequacy of the plant regarding radioactive monitoring and control of release of radioactive material including continuing to meet the MPS3 current licensing basis with respect to the requirements of GDC-60, GDC-64, and 10 CFR 50, Appendix I. Therefore, the proposed SPU is acceptable with respect to the main condenser evacuation system.

2.5.3.3 Turbine Gland Sealing Systems

2.5.3.3.1 Regulatory Evaluation

The turbine gland sealing system is provided to control the release of radioactive material in the turbine to the environment. DNC reviewed changes to the turbine gland system with respect to factors that may affect gaseous radioactive material handling (e.g., source of sealing steam, system interfaces, and potential leakage paths).

The acceptance criteria for the turbine gland sealing system are based on

- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents.
- GDC-64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released for normal operations, including anticipated operational occurrences and postulated accidents.

Specific review criteria are contained in the SRP, Section 10.4.3, and other guidance provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Section 10.4.3, Rev. 2. As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 turbine gland sealing system regarding conformance to the following:

- GDC-60 is described in FSAR Section 3.1.2.60, Control of Releases of Radioactive Materials to the Environment (Criterion 60).

  The design for radioactivity control is based on

  1. The requirements of 10 CFR 20, 10 CFR 50, and Appendix I to 10 CFR 50 for normal operations and for any transient situation that might reasonably be anticipated to occur.

  2. 10 CFR 50.67 dose level guidelines for potential accidents of extremely low probability of occurrence.

  All release paths, including ventilation and process streams, are monitored and controlled as described in the FSAR Section 11.5, Process, Effluent and Airborne Monitoring Systems. Radioactive gaseous waste effluent activity levels are monitored subsequent to release through the Millstone 375 foot stack. Under conditions of concurrent fuel failure and steam generator tube leakage, radioactive gas, if present, will be suitably controlled in the steam jet air ejector discharge in the condenser air removal system (FSAR Section 10.4.2) and in the flow from the steam packing exhauster fan in the turbine generator gland seal and exhaust system (FSAR Section 10.4.3). The steam jet air ejector discharge is directed to the Millstone stack while the seal steam packing exhauster fan discharges through the condensate polishing enclosure roof.

- GDC-64 is described in FSAR Section 3.1.2.64, Monitoring Radioactivity Releases (Criterion 64).

  Normal unit effluent discharge paths are monitored during normal plant operation by ventilation particulate samples and gas monitors in the auxiliary building and engineered safety buildings (FSAR Section 11.5). After a postulated accident, the safety-related ventilation vent monitors and the safety-related supplemental leak collection and release system monitors are used to monitor the effluents from spaces contiguous to the containment structure. Radioactivity levels in the environs are controlled during normal and accident conditions by various radiation monitoring systems described in FSAR Section 11.5, Process, Effluent and Airborne Radiation Monitoring Systems and FSAR Section 12.3.4, Area Radiation and Airborne Radioactivity Monitoring, and monitored by the collection of samples as part of the offsite radiological monitoring program.

There is no radiation monitoring at the gland seal condenser vent, as radioactive gaseous releases fall within the total unmonitored steam release specifications from the Turbine Building as defined in NUREG-0017, Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents From Pressurized Water Reactors, April 1976, Section 2.2.6.

The turbine gland sealing system is described in the FSAR Section 10.4.3. The turbine gland sealing system prevents air leakage into, and collects steam leakage out of the turbines and vent stems. It functions automatically from startup to full load. This system is not safety-related.

In addition to the evaluations described above, the turbine gland sealing system was evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. The turbine gland sealing system is not within the scope of license renewal.

2.5.3.3.2 Technical Evaluation

2.5.3.3.2.1 Introduction

The turbine gland sealing steam and exhaust system is an automatically operated system that prevents air leakage into and steam leakage from the main turbine and main feed pump turbines. The system also collects gland steam leakoff and leakoff from the main steam stop valves, control valves, and combined intermediate valves.

The high-pressure and low-pressure turbines, and the main feed pump turbines, have labyrinth seals to provide a high resistance to steam or air flow along the shaft. Gland sealing steam is provided to the gland seal chamber to maintain 3-5 psig under all operating conditions. Excess steam leaks off the glands and is collected in the gland steam condenser. Condensed steam drains from the gland steam condenser to the main condenser.

For plant startup, sealing steam is initially supplied from main steam upstream of the main turbine stop valves. Auxiliary steam is used to seal the main turbine and main feed pump turbines when initially drawing condenser vacuum in the absence of main steam. During intermediate load operation, steam supply is transferred to extraction steam from the A low-pressure turbine prior to entering the fourth point feedwater heaters. During high load operations, the turbine pressure increases and leakage from the high-pressure turbine glands supplies the steam sealing requirements for the low-pressure turbines.

To prevent steam escaping from the glands to the Turbine Building, the gland steam condenser maintains a pressure below atmospheric in the gland leakoff system. The steam-air mixture from the packing annuli enters the gland steam condenser. The condensate system provides steam condenser cooling. Condensed steam is drained to the main condenser. Entrained air and other noncondensible vapors leaving the gland steam condenser are discharged through an atmospheric vent by one of two air exhausters.

The turbine gland sealing system is a non-safety-related system.

2.5.3.3.2.2 Description of Analyses and Evaluations

The turbine manufacturer, General Electric, performed an SPU study to assess the capability of existing equipment to handle a power uprate to 107 percent. The turbine gland sealing system was included in the “Stretch Power Uprate Study Report – Steam Turbine/Generator for Dominion Nuclear Connecticut Millstone Power Station Unit 3.” The evaluation assessed whether changes were required to the existing system and component design in order to meet their design functions during power uprate conditions.

FSAR Table 11.3-1 indicates expected annual radioactivity releases to the atmosphere from MPS3, including the turbine gland sealing system. These values were determined using the guidance from NUREG-0017. Four years of monitoring (1986-1989) showed that the turbine gland sealing system did not contribute to any measurable radioactivity releases. Based on these results, the calculational methodology for turbine gland sealing system radioactivity monitoring implemented in 1985 was eliminated. DNC completed a calculation, to determine if any significant changes would result from the SPU implementation.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 License Renewal Application for the turbine gland sealing system. Section 2.5.3.3.1 states that the evaluation of turbine gland sealing was not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for license renewal and they remain valid for the SPU conditions.

2.5.3.3.2.3 Results

The turbine gland sealing system operates to maintain gland steam pressure at approximately 3-5 psig in the gland areas. The system is sized based on steam and air flows resulting from twice the normal seal clearances. Steam supply during intermediate load operation is extraction steam from the A low-pressure turbine prior to entering the fourth point feedwater heaters. A pressure control valve maintains sealing steam pressure. At high turbine loads, the turbine gland steam system is designed to be a self-sealed system. As turbine load increases, the turbine pressure increases and leakage from the high-pressure turbine glands supplies the steam sealing requirements for the low-pressure turbines. When leakoff flow from the high-pressure turbine exceeds the sealing requirements, excess steam is discharged through a steam packing unloading valve to the main condenser. Increased steam flow has minimal effect on system operation.

The increase in steam flow from the main feed pump turbines and high-pressure turbine gland leakoff lines and main stop valves, main control valves, and intermediate combined valves leakoff is approximately 7 percent. This increase in steam flow is within the system capabilities and will not adversely affect gland steam condenser operation. From a system standpoint, the additional cooling flow requirement from the condensate system is negligible and will not effect condensate system operation.

The proposed power uprate will not significantly increase the exhaust flow from the gland seal condenser. Minor exhaust flow increases are within the existing system capabilities.

The turbine gland sealing system was included in the power uprate evaluation provided by the turbine vendor General Electric "Stretch Power Uprate Study Report – Steam Turbine/Generator for Dominion Nuclear Connecticut Millstone Power Station Unit 3." The evaluation concluded that no system changes were necessary. Minor steam flow changes will not affect the design of system components. From a system standpoint, the additional cooling flow requirement from the condensate system is negligible. No physical changes to system components or changes in system operation are warranted by the slight increase in sealing flow and gland steam condenser cooling flow. The existing turbine gland sealing system can provide the proper sealing flow for the affected components. Since the gland steam condenser vent does not monitor radioactive releases, changes are not required to the existing system operation.

Since there is no installed radiation monitoring at the gland seal condenser vent, radiation monitoring of the gland seal condenser exhaust line is unaffected by the proposed power uprate. Calculation 06-ENG-04218R3 determined that the radioactivity releases from the turbine gland sealing system after SPU implementation continue to fall within the Turbine Building total unmonitored steam-release specifications as defined in NUREG-0017. No changes are required as a result of the SPU.

2.5.3.3.3 Conclusion

DNC has reviewed the evaluations related to the effects of the proposed SPU on the turbine gland sealing system. DNC concludes that the evaluations have adequately accounted for the proposed SPU effects on the turbine gland sealing system. The turbine gland sealing system will continue to maintain its design functions, and meet the MPS3 current licensing basis with respect to the requirements of GDC-60 and GDC-64 following proposed SPU implementation. Refer to Section 2.10.1, Occupational and Public Radiation Doses for a discussion of plant adequacy regarding radioactive monitoring and release of radioactive material. Therefore, DNC finds the proposed SPU acceptable with respect to the turbine gland sealing system.

2.5.4 Component Cooling and Decay Heat Removal

2.5.4.1 Spent Fuel Pool Cooling and Cleanup System

2.5.4.1.1 Regulatory Evaluation

The spent fuel pool provides wet storage of spent fuel assemblies. The safety function of the spent fuel pool cooling and cleanup (purification) system is to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. The DNC review for the proposed SPU focused on the effects of the proposed SPU on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions.

The acceptance criteria for the spent fuel pool cooling and purification system are based on

- GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions.
- GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided.
- GDC-61, insofar as it requires that fuel storage systems be designed with residual heat removal (RHR) capability reflecting the importance to safety of decay heat removal and measures to prevent a significant loss-of-fuel-storage coolant inventory under accident conditions.

Specific review criteria are contained in SRP Section 9.1.3, as supplemented by the guidance provided in RS-001, Section 2.1, Matrix 5, Attachment 2.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Section 9.1.3, Rev. 1. MPS3 took the following exceptions to SRP 9.1.3, Rev. 1:

- Section III.1.d (4) – Decay heat removal is based on HOLTEC's DECOR (based on ORIGEN2) computer code and credit for evaporative cooling instead of BTP ASB 9-2.
- Section III.1.d – The maximum bulk water temperature for a normal heat load is 150°F.
- Section III.1.h (ii) – The decay time for the maximum heat load is based on the heat removal capacity of the spent fuel pool heat exchangers and varies from 165 hours to 349 hours after reactor shutdown.

As noted in the FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the GDC is discussed in FSAR Section 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 spent fuel pool cooling and purification system regarding conformance to the following:

- GDC-5 is described in the FSAR Section 3.1.2.5, Sharing of Structures, Systems and Components (Criterion 5)

The MPS3 spent fuel pool cooling and purification system is a unit specific system that is not shared.

- GDC-44 is described in the FSAR Section 3.1.2.44, Cooling Water (Criterion 44)

  The reactor plant component cooling water system, the charging pump cooling system, spent fuel pool cooling and purification system, and the safety injection pump cooling system transfer heat from systems containing reactor coolant to the service water system. Together, these systems transfer heat to the ultimate heat sink from structures, systems, and components important to safety during normal and accident conditions.

  These systems are designed with suitable redundancy in components, with leak protection, and with the capability to isolate redundant components. The systems are designed to satisfy the cooling water requirements assuming a single failure and either a loss of onsite or offsite power.

- GDC-61 is described in the FSAR Section 3.2.1.61, Fuel Storage and Handling and Radioactive Control (Criterion 61)

  Decay heat from spent fuel is dissipated in the water of the spent fuel pool and subsequently removed by the cooling portion of the fuel pool cooling and purification system (FSAR Section 9.1.3). Redundancy of fuel pool cooling and purification system components ensures reliability in controlling the spent fuel pool water temperature. Spent fuel pool cooling system operation is continuously monitored in the main control room where spent fuel pool water temperature is both indicated and alarmed. Special tests are not required because at least one pump and heat exchanger are normally in operation when spent fuel is stored in the spent fuel pool.

  The piping connected to the spent fuel pool is designed so that an acceptable water level is maintained in the event of a pipe rupture. Instrumentation to annunciate spent fuel pool water level changes above or below preset levels is provided on the fuel pool control panel in the main control room. Redundancy of makeup water sources ensures adequate supply and availability of makeup to the spent fuel pool, even under loss of normal electrical power.

When MPS3 was first licensed, a full core offload was categorized as an abnormal event. MPS3 submitted a license amendment request on January 18, 1999, to formalize a licensing basis change to reclassify the full core offload as a normal evolution. This change also increased the maximum design basis normal spent fuel pool (SFP) bulk water temperature from 140°F to 150°F. The NRC forwarded a request for additional information (RAI) on October 7, 1999. MPS3 responded to this RAI in a letter dated December 21, 1999. The spent fuel pool cooling analysis submitted in the January 18, 1999 letter, and the additional information provided in the RAI response summarize the current MPS3 spent fuel pool cooling system analysis of record. The NRC issued Amendment 182 on September 12, 2000 approving this request.

Additional details that define the licensing basis for the SFP cooling and purification system are described in FSAR Section 9.1.3, Fuel Pool Cooling and Purification System.

Technical Specification (TS) 3/4.9.1 (3.9.1.2), Boron Concentration, ensures that the SFP boron concentration is maintained ≥ 800 ppm.

MPS3 TS 3/4.9.3, Decay Time, ensures that irradiated fuel has sufficiently reduced heat load prior to movement.

MPS3 TS 3/4.9.11, Water Level – Storage Pool, ensures that at least 23 feet of water is maintained over the top of irradiated fuel assemblies in the SFP storage racks.

MPS3 TS Section 5.6 provides the design features for fuel storage, including criticality, drainage, and capacity. The SFP contains 350 Region 1, 673 Region 2, and 756 Region 3 storage locations, for a total of 1779 available fuel storage locations. An additional Region 2 rack with 81 storage locations may be placed in the SFP, if needed. The Region 2 storage capacity increases to 754 location with this additional rack installed, bringing the total available fuel storage locations to 1860 (licensed capacity).

The SFP cooling and purification system was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, defines the scope of license renewal. NUREG-1838 Sections 2.3B.2.5 and 3.2B.2.3.5 are applicable to the SFP cooling and purification system.

2.5.4.1.2 Technical Evaluations

2.5.4.1.2.1 Introduction

The primary function of the SFP cooling system is to remove the decay heat from the irradiated spent fuel assemblies stored in the SFP. A secondary function is to maintain SFP water purity and clarity.

The safety-related SFP cooling system consists of one loop with two 100 percent capacity, Seismic Category 1, and Safety Class 3 cooling trains, each equipped with one pump and one heat exchanger. Heat is removed from the SFP heat exchangers by the reactor plant component cooling CCP system. Normally, one SFP cooling pump and its associated heat exchanger are in service. The cooled water is returned to the SFP, where natural circulation removes heat from the stored fuel assemblies. Each pipe entering the SFP has a vent hole to act as an anti-siphoning device or terminates at an elevation above these vent holes. These provisions prevent SFP water siphoning and uncovering the spent fuel.

The non-safety-related SFP purification system has a coarse filter, redundant 100 percent capacity pumps, redundant pre-filters, a demineralizer, and a post filter to purify SFP water. Skimmers remove surface debris to improve water clarity. The filters and demineralizer remove fission products, corrosion products, and resin fines from the SFP water. The purification subsystem can be manually isolated from the SFP cooling subsystem.

Normal SFP make-up water is the primary grade water system. The RWST, a Seismic Category 1 source, can provide make-up water if primary grade water is unavailable or a borated water source is required. Another water source is a fire protection system hose station located near the SFP. In the unlikely failure of both cooling trains and loss of all these water sources, a Seismic Category 1, Safety Class 3 flow path is available from the service water system by removing blank flanges and installing the normally removed spool piece.

Level transmitters monitor SFP levels and provide high- and low-level alarms on a local panel and in the main control room. Temperature transmitters monitor SFP temperature and provide a high temperature alarm on a local panel and in the main control room.

Other related evaluations are addressed in the following Licensing Reports:

- Section 2.5.4.3, Reactor Auxiliary Cooling Water Systems (Cooling Water Systems)
- Section 2.7.4, Spent Fuel Pool Area Ventilation System
- Section 2.8.6.2, Spent Fuel Storage

SFP temperature is verified ≤ 150°F on the control room daily surveillance forms for the associated operating mode:

Modes 1-4	SP 3670.1-001
Mode 5, 6 and defueled	SP 3670.1-017

2.5.4.1.2.2 Description of Analyses and Evaluations

2.5.4.1.2.2.1 Method of Calculation

The current analysis of record demonstrates that the MPS3 SFP cooling system heat removal capability is sufficient to maintain the required SFP temperature. The existing analysis of record is still bounding for the SPU conditions.

The SFP cooling system was evaluated to determine if it would continue to perform its intended functions at the SPU conditions. The existing design basis heat load calculations were reviewed to determine which SFP heat load values could be impacted. ORIGEN-ARP calculations were then performed to determine the SPU effect on SFP heat loads. After determining the increase in SFP heat loads, the analyses of record was reviewed for impacts.

The existing design basis SFP heat load consists of a full pool of MPS3 fuel plus a 3.8 x 10^6 Btu/hr decay heat allowance for Millstone Unit 1 (MPS1) and 2 (MPS2) fuel stored in the MPS3 SFP. This allowance is included in the MPS3 SFP heat load analysis of record to support MPS1 or MPS2 fuel storage in the MP3 SFP. MPS1 or MPS2 fuel is not currently stored in the MPS3 SFP, and there are no plans to store MPS1 or MPS2 fuel in the MPS3 SFP. Fuel storage racks for the MPS1 or MPS2 fuel were never installed in the MPS3 SFP. This option is no longer necessary with the construction of the Millstone ISFSI. Since MPS1 or MPS2 fuel will not be stored in the MPS3 SFP, the associated 3.8 x 10^6 Btu/hr decay heat allowance is unallocated margin in the existing SFP design analysis. The maximum calculated increase in SFP heat load due to the SPU is less than the existing 3.8 x 10^6 Btu/hr margin in the heat load analysis. Thus, the existing heat load analysis is still bounding.

The SFP analysis of record was performed using a 95°F CCP temperature as the upper limit to ensure the results were bounding. This CCP temperature for the SFP heat exchangers corresponds to a 75°F ultimate heat sink temperature.

SPU implementation does not require a change to system flows, pressures, or temperatures. The evaluations determined whether the existing SFP cooling system design parameters meet the SPU conditions for the following design aspects:

- Design pressure/temperature of piping and components
- Flow velocities
- Cooling capacity – normal full core offload
- Cooling capacity – emergency full core offload
- Cooling capacity – normal operation/loss of fuel pool cooling
- Concrete wall temperature

2.5.4.1.2.2.2 Design Pressure/Temperature of Piping and Components

The SFP cooling system piping and component design pressures and temperatures were evaluated for SPU conditions. Following SPU implementation, the SFP cooling system will operate at temperatures and heat loads within the current system design basis. The SPU does not result in any SFP cooling system changes that would increase system operating pressures. Therefore, the SFP cooling system piping and components are bounded by the existing SFP cooling analysis for the SPU.

2.5.4.1.2.2.3 Flow Velocities

There are no SFP cooling and purification subsystems modifications. Pump performance is unchanged following SPU implementation. Therefore, the flow velocities are not changing and are bounded by the original system design conditions and will remain bounded at SPU conditions. In addition, NPSH, BHP, and pump head are not impacted by SPU implementation.

2.5.4.1.2.2.4 Cooling Capacity

Normal refueling operations are conducted approximately every 18 months. Full core offload into the SFP are typically performed during each refueling. The SFP cooling system must be capable of maintaining the SFP bulk temperature ≤ 150°F, considering the heat load from the full core offload and the SFP background decay heat loads. Full core offload is defined as placing all the reactor core fuel (193 fuel assemblies) in the SFP. The background decay heat loads are the sum of the decay heat loads from all individual fuel batches residing in the SFP.

The SFP cooling system is designed to keep the bulk SFP temperature below 150°F for Case 1 – normal full core offload, Case 2 – emergency full core offload, and Case 3 – normal operation/loss of fuel pool cooling.

Normal Full Core Offload –

The SFP cooling system was evaluated for decay heat load from a full core offloaded into the SFP, with all other SFP storage locations filled with spent fuel.

Emergency Full Core Offload –

A full core at the end-of-life offloaded to the SFP after 36 days of full–power operation following an outage lasting 10 days. The heat load to the SFP is fully bounded by the normal full core offload heat load and further review is not required.

Normal Operation – Loss of Fuel Pool Cooling –

The SFP cooling system was evaluated for decay heat load from the latest refueling fuel discharge (97 fuel assemblies) into the SFP, with 25 days (600 hours) of decay time and the same background decay heat load used for a normal full core offload. Following a design basis accident with loss of power, SFP cooling is lost for approximately 4 hours prior to restoration. During this time period, SFP cooling is limited to evaporative heat loss.

2.5.4.1.2.2.5 Concrete Wall Temperature

There is no impact to the maximum concrete wall temperature at SPU conditions, as SFP heat loads and temperatures remain bounded by the existing design basis.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for the SFP cooling and purification system. The SFP cooling and purification system is within the scope of license renewal. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating the SFP cooling and purification system at SPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.4.1.2.3 Results

2.5.4.1.2.3.1 System/Component Design Parameters

The SFP cooling and purification system piping and components are acceptable at SPU conditions. Equipment modifications are not required. The following SPU evaluation summary demonstrates that the existing SFP cooling system analysis of record is still bounding.

2.5.4.1.2.3.2 Cooling Capacity – Normal Full Core Offload

Existing Analysis of Record

The NRC approved the existing SFP cooling system analysis of record in MPS3 License Amendment 182. A detailed description of this analysis is contained in the MPS3 license amendment request dated January 18, 1999. The existing analysis of record is summarized below:

- The maximum projected SFP heat load is 45.41 x 10^6 Btu/hr. This decay heat load is based on a total of 1960 MPS3 fuel assemblies and 1088 MPS1 and/or MPS2 fuel assemblies stored in the MPS3 SFP. This is conservatively larger than the MPS3 TS licensed fuel storage capacity of 1860 MPS3 fuel assemblies.
- The maximum SFP bulk water temperature with a single train of SFP cooling is 150°F.
- Conservative values for SFP and CCP cooling flows are used. Conservative assumptions on SFP cooling heat exchanger tube plugging are used.
- The thermal-hydraulic analysis credits evaporative cooling to the Fuel Building environment as a SFP decay heat removal mechanism.
- The 108°F SFP ambient air temperature assumed in the evaporative cooling analysis is based on a steady-state pool temperature of 150°F.
- The delay time after reactor shutdown for beginning fuel transfer to the SFP is dependent on CCP temperature, which cools the SFP cooling heat exchangers. The analysis used CCP temperatures of 80°F, 85°F, 90°F, and 95°F to determine the allowable time after reactor shutdown to begin fuel offload to the SFP.
- The analysis assumed a fuel transfer rate of 3 assemblies per hour from the reactor vessel to the SFP.

The existing SFP cooling system analysis of record allows for core offload to begin as early as 101 hours after shutdown, provided the CCP temperature to the SFP cooling heat exchangers is ≤ 80°F. A full core offload to the SFP commencing 101 hours after shutdown results in the maximum SFP decay heat load after completion. For CCP temperatures between 80°F and 95°F, additional calculations are performed. These CCP temperatures result in longer required delay times prior to commencing core offload. Longer delay times reduce the SFP decay heat load, ensuring it remains within the capability of the SFP cooling system. With a core offload begun 101 hours after shutdown and fuel offloaded at transfer rate of 3 assemblies per hour, 165 hours after reactor shutdown results in the maximum SFP decay heat load of 45.41 x 10^6 Btu/hr. This heat load is comprised of 34.27 x 10^6 Btu/hr from the 193 offloaded fuel assemblies and 11.14 x 10^6 Btu/hr from the background decay heat load of 1767 fuel assemblies (1960 total – 193 offloaded) in the SFP. Background decay heat load includes the 3.8 x 10^6 Btu/hr allowance for MPS1 and/or MPS2 fuel assemblies (1088 total) stored in the MPS3 SFP. The maximum heat load (45.41 x 10^6 Btu/hr) is removed by the SFP cooling heat exchanger (43.53 x 10^6 Btu/hr) and through evaporative cooling (1.88 x 10^6 Btu/hr) at a SFP bulk water temperature of 150°F.

Evaporative cooling from the SFP surface is a function of SFP bulk water temperature and Fuel Building ambient atmosphere temperature. HOLTEC's ONEPOOL computer code was used in the design basis calculation to determine the SFP evaporative cooling rate. This model was previously benchmarked against SFP water heatup test data. The calculated evaporative heat loss rate is 1.88 x 10^6 Btu/hr from the SFP surface at 150°F bulk SFP water temperature.

The cooling rates from the SFP cooling heat exchanger and evaporative cooling from the SFP surface must equal or exceed the maximum decay heat input to maintain a SFP bulk water temperature less than or equal to 150°F. With a maximum SFP bulk pool temperature of 150°F and CCP temperatures 80°F - 95°F, the SFP maximum heat removal capacity (heat exchangers and evaporative cooling) is 45.41 x 10^6 Btu/hr to 36.08 x 10^6 Btu/hr.

The decay heat load in the SFP must be maintained below the levels listed above to maintain the bulk SFP temperature below 150°F. Decay heat from irradiated fuel decreases with time after reactor shutdown. Using a fuel transfer rate of 3 assemblies per hour, the minimum time after reactor shutdown to start a core offload varies from 101 to 285 hours. These times correspond to an 80°F to 95°F CCP temperature. The maximum SFP heat load occurs when the core is fully offloaded to the SFP, which takes approximately 64 hours to complete at a fuel offload rate of 3 assemblies per hour. Adding 64 hours to the core offload start time results in a maximum SFP heat load at 165 to 349 hours after reactor shutdown, for an 80°F to 95°F CCP temperature. Procedural controls are in place to ensure that the number of fuel assemblies moved to the SFP from the core offload, versus time after shutdown, is limited to that allowed by the SFP cooling analysis of record.

In addition to the SFP cooling analysis, there are other limits on fuel movement to the SFP. The Technical Specification on decay time prohibits the movement of irradiated fuel in the reactor vessel until the reactor is subcritical for at least 100 hours. There is also a 132-hour minimum fuel decay time prior to placing fuel in certain Westinghouse-manufactured fuel storage racks. This limit is based on compliance with the thermal and stress analysis these racks.

The full core offload decay heat load is calculated by conservatively assuming that all 193 offloaded fuel assemblies are 5 w/o fuel at 60,000 mwd/mtu. These fuel assemblies are Westinghouse 17x17 with 455 kgs uranium per assembly. The background decay heat load is calculated by assuming all available 1767 SFP locations (1960 total – 193 offloaded) contain fuel from previous cycle discharges. A detailed account of the 1767 fuel assemblies that constitute the background decay heat load, including the breakdown of calculated decay heat load by batch, was previously submitted to the NRC in a letter dated December 21, 1999.

SPU Impact on Analysis of Record

The SPU increases the SFP decay heat load. This increase comes from two sources. Operation at higher power levels increases the amount of decay heat from the fuel assemblies in a full core offload. Also, continued operation at the SPU results in previous discharge batches with higher decay heat loads, which increases the SFP background decay heat load. Therefore, the total increase in SFP decay heat load due to the SPU is the sum of the increase from a full core offload, and the increase in background decay heat load.

The SPU-related increase in SFP decay heat load from a full core offload was calculated as 2.173 x 10^6 Btu/hr using ORIGEN-ARP. This calculation assumes an SPU power level of 3650 Mwt after 165 hours of fuel decay time. The 165 hours is used since that is the shortest decay time to reach maximum SFP heat load. The SPU-related increase in SFP background decay heat load was calculated as 0.264 x 10^6 Btu/hr using ORIGEN-ARP. Therefore, the total SPU increase in SFP decay heat load for a full core offload is 2.44 x 10^6 Btu/hr.

As previously discussed, the existing SFP cooling system analysis of record contains a 3.8×10^6 Btu/hr allowance in the background decay heat load to support the potential storage of MPS1 and/or MPS2 fuel in the MPS3 SFP. MPS1 or MPS2 fuel is not currently stored in the MPS3 SFP, and there are no plans to store MPS1 or MPS2 fuel in the MPS3 SFP. The SFP decay heat load was calculated to increase by a total of 2.44×10^6 Btu/hr due to the SPU. This increased decay heat load is more than offset by the 3.8×10^6 Btu/hr margin gain by not placing MPS1 and/or MPS2 fuel in the MPS3 SFP. The existing design basis heat load bounds the decay heat load resulting from SPU operation. SPU values for full core offload heat load are bounded by the existing values, therefore, SFP temperatures for full core offload are also bounded by the existing analysis.

2.5.4.1.2.3.3 Cooling Capacity – Emergency Full Core Offload

The decay heat load for an Emergency Full Core offload is bounded by the decay heat load for a Normal Full Core offload and further review is not necessary.

2.5.4.1.2.3.4 Cooling Capacity – Normal Operation/Loss of Fuel Pool Cooling

Two conditions were evaluated: (1) SFP operation during the operating cycle, and (2) Loss of SFP cooling during the operating cycle.

Spent Fuel Pool Operation During the Operating Cycle

Existing Analysis of Record

MPS3 submitted a license amendment request on January 18, 1999, that contains a detailed description of the existing SFP cooling analysis of record. The existing analysis of record is summarized below:

Normal operation refers to the time period between refueling outages, beginning after core reload when the plant has re-entered Mode 4. The existing analysis of record decay heat load for normal operation is 21.1×10^6 Btu/hr. This value is the sum of the decay heat load from the most recent discharge batch of fuel and the background decay heat load from all the other SFP fuel. SFP heat exchanger cooling is assumed at the maximum CCP temperature of 95°F. The heat load is calculated as 9.96×10^6 Btu/hr from the most recently discharged fuel batch, and 11.14×10^6 Btu/hr of background decay heat load from the 1767 stored fuel assemblies. Background decay heat load includes a 3.8×10^6 Btu/hr allowance for MPS1 and/or MPS2 fuel assemblies (1088 total) stored in the MPS3 SFP. The decay heat load from the most recently discharged fuel consists of 97 fuel assemblies, at a decay time of 600 hours (25 days). The background decay heat load calculation is the same as previously described for a full core offload.

The SFP heat load was calculated for the normal operating cycle using a refueling outage duration of 25 days from reactor shutdown (sub-criticality) until re-entry into Mode 4, when a design basis accident becomes credible. Refueling outages of less than 25 days duration, or refueling outages with greater than 97 fuel assemblies discharged to the SFP after core reload require evaluation on a case-by-case basis to ensure that the SFP decay heat levels remain $\leq 21.1 \times 10^6$ Btu/hr.

SPU Impact on Analysis of Record

The SPU-related increase in decay heat load was calculated as 0.86×10^6 Btu/hr using ORIGEN-ARP. This increased SFP decay heat load is more than offset by the 3.8×10^6 Btu/hr margin gain by not placing MPS1 and/or MPS2 fuel in the MPS3 SFP. The existing design basis heat load bounds the decay heat load resulting from SPU operation, and the existing analysis for this remains valid. SFP temperatures at SPU are also bounded by the existing design basis values for this condition. Since the limiting SFP decay heat load values have not changed, the SFP temperature heat-up rates from a loss of SFP cooling have not changed.

Loss of Spent Fuel Pool Cooling During the Operating Cycle

Existing Analysis of Record

Following a design-basis accident with a concurrent loss of power, CCP to the SFP cooling heat exchangers is not available until approximately 4 hours after the accident. During this time, SFP cooling is limited to evaporative cooling from the SFP surface. The total bounding SFP decay heat load of 21.1×10^6 Btu/hr is assumed, resulting in a calculated temperature of 127.6°F at the start of this event. Cooling is restored to the SFP cooling heat exchangers after 4 hours. The maximum bulk SFP temperature at the end of 4 hours is 148.8 °F. This is acceptable, since the SFP bulk water temperature is maintained less than 150°F.

The SFP heat load was calculated for the normal operating cycle using a bounding duration of 25 days from reactor shutdown (sub-criticality) until re-entry into Mode 4, where a design basis accident becomes credible. Refueling outages of less than 25 days duration, or refueling outages with greater than 97 fuel assemblies discharged to the SFP after core reload, require evaluation on a case-by-case basis to ensure that the SFP decay heat levels remain $\leq 21.1 \times 10^6$ Btu/hr.

SPU Impact on Analysis of Record

The SPU related increase in decay heat load was calculated as 0.86×10^6 Btu/hr using ORIGEN-ARP. This increased SFP decay heat load is more than offset by the 3.8×10^6 Btu/hr margin gain by not placing MPS1 and/or MPS2 fuel in the MPS3 SFP. MPS1 or MPS2 fuel is not currently stored in the MPS3 SFP, and there are no plans to store MPS1 or MPS2 fuel in the MPS3 SFP. The existing design basis heat load bounds the SPU decay heat load. Thus, the existing analysis for a loss of SFP cooling during the operating cycle remains valid. The existing SFP temperatures bound the SPU SFP temperatures for this event.

2.5.4.1.2.3.5 Single Active Failure Considerations

Existing Analysis of Record

MPS3 submitted a license amendment request on January 18, 1999, that contains a detailed description of the existing SFP cooling analysis of record. Additional information was previously provided to the NRC in our December 21, 1999, letter associated with MPS3 Amendment 182. The existing analysis of record is summarized below:

The SFP cooling system design meets the single active failure design criterion. The system consists of two 100 percent capacity trains with independent safety grade cooling and electrical support systems. The thermal-hydraulic analysis uses only 1 train of SFP cooling. A single train of SFP cooling has sufficient heat removal capacity to maintain the SFP ≤150°F at all times during normal operation.

A SFP cooling system single active failure was evaluated at the limiting 150°F SFP bulk water temperature. The failure is assumed to disable the active cooling train with 30 minutes required to place the standby cooling train into service. Should this failure occur during refueling at the peak SFP temperature, SFP bulk water temperature would increase to approximately 155.7°F before cooling was restored, and SFP bulk water temperature returned to less than 150°F. The SFP systems, structures, and components are all designed for normal operation at the environmental and service conditions that would result from a steady state pool temperature of 155.7°F.

SPU Impact on Analysis of Record

The maximum heat load used in the single active failure analysis is associated with a full core offload. As previously discussed, the SPU related increase in decay heat load from a full core offload to the SFP was calculated as 2.44×10^6 Btu/hr. This increased decay heat load is more than offset by the 3.8×10^6 Btu/hr margin gain by not placing MPS1 and/or MPS2 fuel in the MPS3 SFP. MPS1 or MPS2 fuel is not currently stored in the MPS3 SFP, and there are no plans to store MPS1 or MPS2 fuel in the MPS3 SFP. The existing design basis heat load for this event bounds the decay heat load resulting from SPU operation. SPU values for heat loads following core offload are bounded by the existing values; therefore, SPU SFP temperatures are also bounded.

2.5.4.1.2.3.6 Time to Boil Considerations

Existing Analysis

In the unlikely occurrence of a complete loss of active SFP cooling following a full core offload, the SFP water temperature will begin to rise and eventually reach the boiling temperature. Two redundant primary makeup system pumps (225 gpm each) replenish the SFP inventory loss from evaporation and eventual boiling. The fastest time to boil, assuming a 150°F starting temperature, is 5.47 hours. This time to boil is conservatively calculated using the maximum heat load at the completion of a core offload. A conservative calculation of the water loss from the highest decay heat load is about 95 gpm. Each primary makeup system pump has a capacity in excess of the makeup requirements from water loss due to SFP boiling.

The RWST, a Seismic Category 1 source, can provide make-up water if primary grade water is unavailable or a borated water source is required. Another water source is a fire protection system hose station located near the SFP. In the unlikely failure of both cooling trains and loss of all these water sources, a Seismic Category 1, Safety Class 3 flow path is available from the service water system by removing blank flanges and installing the normally removed spool piece.

SPU Impact on Analysis of Record

The full core offload heat load is the maximum heat load used in the existing "time-to-boil" analysis. As previously discussed, the SPU related increase in decay heat load from a full core offload to the SFP was calculated as 2.44×10^6 Btu/hr. This increased decay heat load is more than offset by the 3.8×10^6 Btu/hr margin gain from not placing MPS1 and/or MPS2 fuel in the MPS3 SFP. MPS1 or MPS2 fuel is not currently stored in the MPS3 SFP, and there are no plans to store MPS1 or MPS2 fuel in the MPS3 SFP. The existing design basis heat load for this event bounds the decay heat load resulting from SPU operation. Therefore, the existing design basis analysis time-to-boil calculations are still bounding.

There is no impact to the maximum concrete wall temperature at SPU conditions, as SFP heat loads remain bounded by the existing design basis.

The SPU has no impact on the hydraulic portions of the purification subsystem. The current purification flow rate is adequate for SPU conditions. Equipment changes in the purification loop are not required to support the power uprate. The demineralizer resin replacement frequency is not anticipated to increase appreciably with the SPU. Any increase in fission products resulting from the increased equilibrium RCS radioactivity is mitigated by the RCS cleanup systems prior to fuel assembly transfer to the SFP.

2.5.4.1.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the SFP cooling and cleanup (purification) system. DNC concludes that the evaluation adequately accounted for the proposed SPU effects on the SFP cooling and cleanup (purification) system. Following proposed SPU implementation, the SFP cooling and purification system will continue to maintain its design functions, and will meet the MPS3 current licensing basis with respect to the requirements of GDC-5, GDC-44 and GDC-61. Therefore, DNC finds the proposed SPU is acceptable with respect to the SFP cooling and cleanup (purification) system.

2.5.4.2 Station Service Water System

2.5.4.2.1 Regulatory Evaluation

The station service water system provides essential cooling to safety-related equipment and may also provide cooling to non-safety-related auxiliary components that are used for normal plant operation. The DNC review covered the characteristics of the station service water system components with respect to their functional performance as affected by adverse operational (i.e., water hammer) conditions, abnormal operational conditions, and accident conditions (e.g., a LOCA with loss-of-offsite power). The DNC review focused on the additional heat load that would result from the proposed SPU.

The acceptance criteria for the station service water system are based on:

- GDC-4, insofar as it requires that structures, systems, and components (SSCs) important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, including flow instabilities and loads (e.g., water hammer), maintenance, testing, and postulated accidents
- GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions
- GDC-44, insofar as it requires that a system with the capability to transfer heat loads from important-to-safety SSCs to a heat sink under both normal operating and accident conditions be provided

Specific review criteria are contained in NRC Standard Review Plan (SRP), Section 9.2.1, as supplemented by NRC Generic Letter (GL) 89-13 and GL 96-06, and guidance provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 9.2.1, Rev. 2. An exception was taken to SRP 9.2.1 (Rev. 2) Section III.3.d – Location of radiation monitors. No manual valves in series with motor operated valves are used for the isolation of components susceptible to leakage of radioactive contamination.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 Station design regarding conformance to:

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4)

  SSCs important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5, Tabulation of Codes and Classifications.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-5 is described in FSAR Section 3.1.2.5, Sharing of Structures, Systems and Components (Criterion 5)

  The MPS3 service water system is a unit specific system that is not shared.

- GDC-44 is described in FSAR Section 3.1.2.44, Cooling Water (Criterion 44)

  The reactor plant component cooling water system, the charging pump cooling system, spent pool cooling and purification system and the safety injection pump cooling system, transfer heat from systems containing reactor coolant to the service water system. Together these systems transfer heat to the ultimate heat sink from SSCs important to safety during normal and accident conditions.

  These systems are designed with suitable redundancy in components, with leak protection, and with the capability to isolate redundant components. The systems are designed to satisfy the cooling water requirements assuming a single failure and either a loss of onsite or offsite power.

Additional details that define the licensing basis for the service water system are described in the following FSAR Sections:

- Section 9.2.1 Service Water System
- Section 6.2.4 Containment Isolation System
- Section 9.1.3 Fuel Pool Cooling and Purification System
- Section 9.2.5 Ultimate Heat Sink
- Section 10.4.5 Circulating Water and Associated Systems
- Section 10.4.9 Auxiliary Feedwater System

Technical Specification 3/4.7.4, Service Water System, ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions.

The service water system was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, dated August 1, 2005 documents the results of that review. NUREG-1838 Sections 2.3B.3.2 and 3.3B are applicable to the service water system.

2.5.4.2.2 Technical Evaluation

2.5.4.2.2.1 Introduction

The service water system takes suction from Long Island Sound via the intake structure and supplies cooling water for heat removal from reactor plant auxiliary systems during all modes of operation and for turbine plant auxiliary systems during normal operation. In addition, the service water system provides an emergency source of makeup water for the spent fuel pool, and is the safety-grade long-term emergency source of water for the auxiliary feedwater system.

The service water system consists of two redundant flow paths, each consisting of two service water pumps, two service water self-cleaning strainers, two booster pumps, piping, and valves. The system is designed to provide a continuous supply of cooling water to the following components:

- Reactor plant component cooling heat exchangers
- Turbine plant component cooling heat exchangers
- Containment recirculation coolers
- Control building air conditioning heat exchangers
- Containment recirculation pumps ventilation units
- Residual heat removal pumps ventilation units
- Charging pumps coolers
- Safety injection pumps coolers
- Emergency generator diesel engine coolers
- Service water strainer (backwash)
- Circulating water pumps (lubricating water)
- MCC and rod control area booster pumps
- Post-accident liquid sample cooler

FSAR Table 9.2-1 (Service Water System Flow Requirements) identifies which components are supplied with service water flow for each operating condition.

2.5.4.2.2.2 Description of Analyses and Evaluations

The service water system and components were evaluated to ensure intended functions are performed at SPU conditions. The evaluations compared the existing design parameters of the system/components with SPU conditions relative to the following design aspects:

- Service water system flow and heat removal requirements
- Design pressure/temperature of piping and components
- Overpressurization of isolated piping inside containment and boiling/flow blockage/water hammer effects in service water system piping to the containment recirculation coolers (NRC GL 96-06)
- Fouling in heat exchangers cooled by service water (NRC GL 89-13)

Other evaluations of the service water system and components are addressed in the following sections:

- Piping/component supports and water hammer effects – Section 2.2.2.2, Balance of Plant Piping and Supports (Non-Class 1)
- Protection against dynamic effects, including GDC-4 requirements, of missiles, pipe whip, discharging fluids and flooding effects - Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects
- Safety-related valve and pump testing and valve closure, including containment isolation requirements – Section 2.2.4, Safety-Related Valves and Pumps

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the proposed SPU on the conclusions reached in the MPS3 License Renewal Safety Evaluation Report for the service water system. As stated in Section 2.5.4.2.1, Regulatory Evaluation, the service water system is within the scope of License Renewal. SPU activities will not add any new components nor introduce any new functions for existing components that would change the license renewal evaluation boundaries. With the exception of localized increases in flow temperatures, which are bounded by the design of the system, there are no changes that affect the operation of the service water system at SPU conditions. Additionally, the proposed SPU does not add any new or previously unevaluated materials to the service water system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.4.2.2.3 Results

The existing service water flow rates are not affected by implementation of SPU. As such, the service water pump capacities are acceptable for SPU conditions. The existing service water operating pressures at SPU conditions are also unaffected since no physical changes are being made to the service water system and the pumps continue to operate at current discharge pressure.

The service water system also provides the required water supply to cool the system components for SPU operation for design basis operating scenarios. The higher heat loads for the reactor plant component cooling and turbine plant component cooling heat exchangers during certain SPU operations (e.g., plant cooldown) result in higher service water outlet temperatures (< 120°F / 93°F, respectively). These elevated temperatures are bounded by the design temperature of the reactor plant component cooling heat exchanger (125°F), the design temperature of the turbine plant component cooling heat exchanger (200°F), and the existing stress analyzed temperatures of the heat exchanger outlet piping (125°F/95°F, respectively).

Pre-SPU maximum reactor plant component cooling heat exchanger service water outlet flow temperatures are bounding for SPU normal operation. Consequently, implementation of the proposed SPU will not negatively impact the ability to satisfy the NPDES permit limitation of 100°F at the service water discharge of these heat exchangers. Additionally, given the minor contribution of service water system discharge flow relative to total MPS3 discharge flow in terms of allowable flows (4.32×10^7 gpd versus 1.3132×10^9 gpd, or 30,000 gpm versus approximately 912,000 gpm), these increased heat loads will have no impact on the station's requirement to satisfy the current NPDES permit limitations associated with circulating water discharge.

NRC Generic Letter 96-06

GL 96-06 addresses the potential for thermal overpressurization of isolated water filled segments of piping inside containments. Specifically, GL 96-06 was issued by the NRC to request licensees to determine if containment air cooling water systems are susceptible to waterhammer or two phase flow, and if piping systems that penetrate the containment are susceptible to thermal expansion of fluid so that overpressurization of piping could occur. These issues are not applicable to the MPS3 service water system as this system does not serve the containment air recirculation subsystem, and does not contain any piping penetrating containment.

NRC Generic Letter 89-13

FSAR Section 9.2.1 describes the actions performed to ensure the capability of the service water system to provide the required safety-related cooling. The proposed SPU will not change the flow rate through the service water system. Accordingly, the surveillance and control techniques used to reduce bio-fouling induced flow blockage will not require any changes as a result of implementation of SPU. The proposed SPU will not change the test programs used to verify heat transfer capability of the safety-related heat exchangers cooled by the service water system as there are no flow or pressure changes in the system during normal plant power operation at SPU conditions and the only change in process/operating characteristics of the system due to SPU is a minor increase in temperature during cooldown and accident scenarios.

Inspection and maintenance programs for the service water system piping and components will continue after implementation of SPU. The proposed SPU will not change the maintenance practices and training procedures.

As the arrangement and operation of the service water system is unaffected by the proposed SPU, the existing programs, procedures, and activities in place at MPS3 to support implementation of the GL 89-13 requirements will require no change due to SPU. The program will continue to ensure that the service water system remains reliable and operable after the implementation of SPU.

2.5.4.2.3 Conclusion

DNC has reviewed the evaluation of the effects of the proposed SPU on the station service water system, which included evaluation of the impact of increased heat loads on system performance. DNC concludes the station service water system will continue to provide the required cooling for SSCs important to safety following implementation of the proposed SPU. Additionally, DNC concludes the station service water system will continue to meet the current MPS3 licensing bases with respect to the requirements of GDC-4, GDC-5, and GDC-44 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU is acceptable with respect to the station service water system.

2.5.4.3 Reactor Auxiliary Cooling Water Systems (Cooling Water Systems)

2.5.4.3.1 Regulatory Evaluation

The DNC review covered reactor auxiliary cooling water systems that are required for (1) safe shutdown during normal operations, anticipated operational occurrences, and mitigating the consequences of accident conditions, or (2) preventing the occurrence of an accident. These systems include closed-loop auxiliary cooling water systems for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the emergency core cooling system (ECCS). The DNC review covered the capability of the cooling water systems to provide adequate cooling water to safety-related ECCS components and reactor auxiliary equipment for all planned operating conditions. Emphasis was placed on the cooling water systems for safety-related components (e.g., ECCS equipment, ventilation equipment, and reactor shutdown equipment). The review focused on the additional heat load that would result from the proposed SPU.

The acceptance criteria for the cooling water systems are based on

- GDC-4, insofar as it requires that structures, system, and components important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation including flow instabilities and attendant loads (i.e., water hammer), maintenance, testing, and postulated accidents;
- GDC-5, insofar as it requires that structures, system, and components important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and
- GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related structures, system, and components to a heat sink under both normal operating and accident conditions be provided.

Specific review criteria are contained in SRP Section 9.2.2, and guidance is provided in Matrix 5 of Section 2.1 of RS-001. Additional guidance is supplemented by NRC Generic Letters 89-13 and 96-06.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for Review of Safety Analysis Report for Nuclear Power Plants, July 1981, (NUREG-0800), SRP Section 9.2.2, Rev. 1. MPS3 took exception to SRP 9.2.2 (Rev. 1) Section II.3.e – Loss-of-Coolant test for reactor coolant pumps. The reactor coolant pumps have not been tested for the 20-minute time requirement.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 Station design relative to conformance to

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4).

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents, including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

  Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5, Tabulation of Codes and Classifications.

  FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-5 is described in FSAR Section 3.1.2.5, Sharing of Structures, Systems, and Components (Criterion 5).

  The MPS3 cooling water systems are unit specific systems that are not shared.

- GDC-44 is described in FSAR Section 3.1.2.44, Cooling Water (Criterion 44).

  The reactor plant component cooling water system, the charging pump cooling system, spent fuel pool cooling and purification system, and the safety injection pump cooling system transfer heat from systems containing reactor coolant to the service water system. Together these systems transfer heat to the ultimate heat sink from structures, systems, and components important to safety during normal and accident conditions.

  These systems are designed with suitable redundancy in components, with leak protection, and with the capability to isolate redundant components. The systems are designed to satisfy the cooling water requirements assuming a single failure and either a loss of onsite or offsite power.

Additional details that define the licensing basis for the cooling water systems are described in the following FSAR sections:

- Section 9.2.2.1, Reactor Plant Component Cooling Water System, describes the reactor plant component cooling water system design bases including system description and safety evaluation.
- Section 9.2.2.2, Chilled Water System, describes the chilled water system design bases, which include the system description and safety evaluation.
- Section 9.2.2.3, Neutron Shield Tank Cooling System, describes the neutron shield tank cooler design bases, which include the system description and safety evaluation.

- Section 9.2.2.4, Charging Pumps Cooling System, describes the charging pumps cooling surge tank design bases, which include the system description and safety evaluation.
- Section 9.2.2.5, Safety Injection Pumps Cooling System, describes the safety injection pumps cooling surge tank design bases, which include the system description and safety evaluation.

Component cooling water system LCOs, surveillance requirements, and required action(s) associated with the failure to meet the LCOs are addressed in Technical Specification 3/4.7.3, Reactor Plant Component Cooling System, and the associated Technical Specification Bases.

The cooling water systems were evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.3B.3.4, 2.3B.3.6, 2.3B.3.7, 2.3B.3.8, 2.3B.3.9, and 3.3B are applicable to the cooling water systems.

2.5.4.3.2 Technical Evaluation

2.5.4.3.2.1 Introduction

The reactor plant component cooling (CCP) system is a closed loop system designed to remove heat from plant components during plant operation, plant cooldown, and post accident conditions. CCP water circulates through safety-related and non-safety-related components, where the heat from other systems is transferred to the service water system via component cooling water heat exchangers. The maximum temperature of Long Island Sound and service water of 75ºF is used in the analysis of the CCP system at SPU conditions.

There are three CCP pumps and three CCP heat exchangers in the CCP system. During normal full-power operation, two CCP pumps supply flow to two CCP heat exchangers with the third CCP pump and heat exchanger in standby.

The CCP system serves as an intermediate boundary between the radioactive fluids in the cooled components and the service water system. This arrangement reduces the possibility of radioactive fluid leakage to the environment via the service water system. Radiation monitoring is provided to detect radioactivity entering the system from any of the cooled components, and the system design includes the ability to isolate any component when necessary.

The chilled water system (CDS) is a closed-loop non-safety-related class system with the exception of the containment isolation valves and the piping between them, which are Safety Class 2. The system provides cooling water for the refueling water cooler, service building air conditioning AC units, motor control center and rod control area AC units, containment air recirculation cooling coils, neutron shield tank coolers, and various components inside the containment structure. During loss of power or after receiving a containment isolation phase A signal, cooling water supply to two of the three containment air recirculation coolers and the neutron shield tank coolers is transferred to the CCP system (FSAR Section 9.2.2.2).

The neutron shield tank cooling system (NSS) is a non-safety-related closed cooling water system. It provides cooling water to the neutron shield tank, which is heated by neutron and gamma radiation from the reactor. It is a natural circulation system and consists of two full-capacity neutron shield tank coolers, a surge tank, and associated piping and valves. Makeup water to the system is provided from the non-safety primary grade water system. Heat is rejected in the cooler to the chilled water system or the reactor plant component cooling water system on loss of power or containment isolation phase A signal (FSAR Section 9.2.2.3).

The charging pumps cooling system (CCE) is a safety-related closed cooling water system that transfers the charging pumps lubricating oil coolers heat load to the service water system. This system consists of two full capacity pumps, two full capacity charging pump coolers, a charging pump cooling surge tank, and associated piping and valves. Makeup water to the system is provided by the reactor plant component cooling water system (FSAR Section 9.2.2.1).

The safety injection pumps cooling system (CCI) is a safety-related closed cooling water system that transfers the safety injection pumps bearing oil heat load to the service water system. This system consists of two full capacity pumps, two full capacity safety injection pump coolers, a surge tank, and associated piping and valves. Makeup water to the system is provided by the safety-related portion of the reactor plant component cooling water system (FSAR Section 9.2.2.5).

2.5.4.3.2.2 Description of Analyses and Evaluation

The cooling water systems and components were evaluated to ensure they are capable of performing their intended functions at SPU conditions. The evaluations compared the existing design parameters of the system/components with the SPU conditions for the following design aspects:

- CCP heat exchanger performance (flow rates and temperatures) at the increased SPU heat loads during normal plant operation, plant cooldown, and accident conditions.
- CCP system temperature limits.
- Design pressure/temperature of piping and components versus the SPU operating pressures and temperatures.
- CCP relief valve capacities.

The chilled water system (CDS), neutron shield tank cooling system (NSS), charging pumps cooling system (CCE), and safety injection pumps cooling system (CCI) were also evaluated to ensure they are capable of performing their intended functions at SPU conditions.

Other related evaluations of the cooling water systems and components are addressed in the following Licensing Report sections:

- Piping/component supports – Section 2.2.2.2, Balance of Plant Piping and Supports (Non-Class 1).
- Protection against dynamic effects of missiles, pipe whip, and discharging fluids – Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects and Section 2.5.1.3, Pipe Failures.

- Electrical environmental qualification – Section 2.3.1, Environmental Qualification of Electrical Equipment.
- Safety-related valve and pump testing and valve closure, including containment isolation requirements – Section 2.2.4, Safety-Related Valves and Pumps.
- Protection against turbine missiles and internal missiles – Section 2.5.1.2, Missile Protection.
- Service water fouling in heat exchangers, overpressurization of isolated piping inside containment and boiling/water hammer in service water cooling to the containment atmosphere recirculation coolers (NRC Generic Letters 89-13 and 96-06) – Section 2.5.4.2, Station Service Water System.
- Post-accident heat removal requirements – Section 2.6.1, Primary Containment Functional Design.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal safety evaluation report for reactor plant component cooling (CCP), chilled water (CDS), neutron shield tank cooling (NSS), charging pumps cooling (CCE), and safety injection pumps cooling (CCI) systems. These systems are within the scope of license renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Because no modifications are necessary for the cooling water systems, the SPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.4.3.2.3 Results

During normal operation, cooldown, and safety grade cold shutdown, the CCP heat exchangers are capable of maintaining the cooling water supply temperature to individual cooled components below the following limits:

95ºF	Normal Operation
105ºF	Normal Cooldown
113ºF	Safety Grade Cold Shutdown

A design change to increase the design temperature of the CCP system between the residual heat removal system heat exchangers and the CCP heat exchangers from 150°F to 160°F, and increase the CCP system operating temperature during cooldown modes of operation, will be performed during the SPU implementation.

Additionally, the evaluation of the CCP performance at SPU conditions indicates that the existing CCP system and components operate successfully to supply sufficient flow to cooled components to remove the heat loads at SPU conditions, which includes support of existing fire safe shutdown licensing basis requirements and consideration of the above noted design change.

The calculated increase in maximum CCP temperature differential with SPU results in an approximately 100 gallon increase in system thermal expansion volume relative to the current system volume. The operating band of the CCP surge tank of 483 gallons is sufficient to accept this increase. Additionally, this increase is bound by the volume calculated between the upper limit of the operating band and the level associated with the high level alarm (152 gallons). Additionally, the free volume above the upper limit of 271 gallons exceeds the volume required for the thermal expansion increase. Based on the design of the CCP surge tank, adequate margin is provided to accommodate the thermal expansion at SPU operation. Consequently no level control setpoint changes are required for SPU operation.

The changes in the CCP system and component flow rates are acceptable as a result of SPU. The marginal changes in CCP flow rates to supplied components and total CCP system flow with SPU do not affect the ability of the CCP system to perform intended functions nor exacerbate flow-induced vibration in heat exchangers. There are no new operating modes or system pumping/valve-position lineups required as a result of SPU. The only effect of the SPU is the removal of higher heat loads that result in higher temperatures downstream of the supplied components with higher heat loads. All SPU piping and component temperatures are bound by design conditions. The CCP heat exchangers were assumed to be 10 percent plugged.

The CCP system relief valves either have no change or small changes in temperatures that are bounded by the relief valve design. Since the SPU condition is bounded by the system design temperature/pressure, no additional analysis is required to demonstrate their acceptability.

The NRC issues in Generic Letters 89-13 and 96-06 are related to service water fouling in heat exchangers, heatup and overpressurization of isolated portions of piping inside containment, and boiling/water hammer in service water cooling lines to the containment atmosphere recirculation coolers. The potential impact of the SPU as it relates to the MPS3 responses to NRC Generic Letters 89-13 and 96-06, and subsequent NRC Requests for Additional Information is addressed in Section 2.5.4.2, Station Service Water System.

The evaluation of the chilled water system (CDS), neutron shield tank cooling system (NSS), charging pumps cooling system (CCE), and safety injection pumps cooling system (CCI) performance at SPU conditions indicates that the existing systems and components operate successfully to supply sufficient flow to cooled components and to remove the heat loads at SPU conditions.

2.5.4.3.3 Conclusion

DNC concludes that the reactor plant component cooling (CCP), chilled water (CDS), neutron shield tank cooling (NSS), charging pumps cooling (CCE), and safety injection pumps cooling (CCI) systems will continue to be protected from the dynamic effects associated with flow instabilities and They provide sufficient cooling for structures, systems, and components important to safety, are not shared among nuclear power units, and will continue to have the capability to transfer heat loads from safety-related systems, and components to a heat sink under both normal operating and accident conditions following implementation of the proposed SPU. This conclusion with respect to the CCP system includes the proposed design change that increases the design temperature noted in the Section 2.5.4.3.2.3 above. Based on this, the reactor plant component cooling (CCP), chilled water (CDS), neutron shield tank cooling (NSS), charging pumps cooling (CCE), and safety injection pumps cooling (CCI) systems will continue to meet the MPS3 current licensing basis with respect to the requirements of GDCs -4, -5, and -44. DNC finds the proposed SPU acceptable with respect to the reactor plant component cooling (CCP), chilled water (CDS), neutron shield tank cooling (NSS), charging pumps cooling (CCE), and safety injection pumps cooling (CCI) systems.

2.5.4.4 Ultimate Heat Sink

2.5.4.4.1 Regulatory Evaluation

The ultimate heat sink is the source of cooling water provided to dissipate reactor decay heat and essential cooling system heat loads after a normal reactor shutdown or a shutdown following an accident. The DNC review focused on the impact that the proposed SPU has on the decay heat removal capability of the ultimate heat sink. Additionally, the DNC review included evaluation of the design-basis ultimate heat sink temperature limit determination to confirm that post-licensing data trends (e.g., air and water temperatures, humidity, wind speed, water volume) do not establish more severe conditions than previously assumed.

The acceptance criteria for the ultimate heat sink are based on

- GDC-5, insofar as it requires that structures, systems, and components important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety function; and
- GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related structures, systems, and components to a heat sink under both normal operating and accident conditions be provided.

Specific review criteria are contained in SRP Section 9.2.5 and guidance is provided in Matrix 5 of Section 2.1 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, the July 1981 edition of the Standard Review Plan for Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Section 9.2.5, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design regarding conformance to

- GDC-5 is described in FSAR Section 3.1.2.5, Sharing of Structures, Systems, and Components (Criterion 5).

  The ultimate heat sink is not addressed. Although shared with MPS2, Long Island Sound contains sufficient volume to provide cooling of MPS3 for extended time periods to permit safe shutdown of the unit.

- GDC-44 is described in FSAR Section 3.1.2.44, Cooling Water (Criterion 44).

  The reactor plant component cooling water system, the charging pump cooling system, spent fuel pool cooling and purification system, and the safety injection pump cooling system transfer heat from systems containing reactor coolant to the service water systems. Together these systems transfer heat to the ultimate heat sink from structures, systems, and components important to safety during normal and accident conditions.

These systems are designed with suitable redundancy in components, with leak protection, and with the capability to isolate redundant components. The systems are designed to satisfy the cooling water requirements assuming a single failure and either a loss of onsite or offsite power.

Additional details that define the licensing basis for the ultimate heat sink are described in the following FSAR sections:

- Section 2.4.11.5, Plant Requirements.
- Section 2.4.11.6, Heat Sink Dependability Requirements.
- Section 9.2.1, Service Water.
- Section 9.2.5, Ultimate Heat Sink.

Technical Specification Section 3/4.7.5, Ultimate Heat Sink, ensures that cooling water at or less then the design temperature of 75°F is available to either provide normal cooldown of the facility or mitigate the effects of accident within acceptable limits.

NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, defines the scope of License Renewal. The UHS (Long Island Sound) is not within the scope of License Renewal.

2.5.4.4.2 Technical Evaluation

2.5.4.4.2.1 Introduction

The ultimate heat sink is Long Island Sound, which provides water to the service water system via the intake structure. The service water system provides cooling water for heat removal from safety-related heat exchangers and supplies water from the ultimate heat sink to the auxiliary feedwater system.

A maximum Long Island Sound water temperature of at least 75°F is used for the safety analyses which rely on the ultimate heat sink for heat removal.

Long Island Sound is also used by the non-safety-related circulating water system to provide cooling water for heat removal from the turbine cycle during normal plant power operations.

2.5.4.4.2.2 Description of Analyses and Evaluations

The ultimate heat sink was evaluated to ensure it is capable of performing its intended function of supplying a reliable water source and heat removal capacity for normal and accident conditions following implementation of the proposed SPU.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the UHS evaluation. As stated in Section 2.5.4.4.1, the UHS (Long Island Sound) is not within the scope of license renewal program. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for SPU conditions.

2.5.4.4.3 Results

The ultimate heat sink continues to meet its licensing, design, and performance capabilities at SPU conditions. No changes are required to be made to the UHS Technical Specification due to the SPU.

SPU evaluations demonstrate that the ultimate heat sink will continue to provide cooling water at or at less than the current design basis temperature limitation (75°F) to remove heat from both safety- and non-safety-related cooling systems and transfer the heat ultimately to the environment. The implementation of the proposed SPU does not affect the capability of the ultimate heat sink to perform this function, as demonstrated by the system and component evaluation results documented in Section 2.5.4.2, Station Service Water System (discusses the system capability to cool components important to safety during normal and accident conditions), Section 2.8.4.4, Residual Heat Removal System (discusses the cooldown scenarios which use the ultimate heat sink for heat rejection), Section 2.5.8.1, Circulating Water System (discusses the system capability to condense the steam exhausted from the low-pressure turbines and cool miscellaneous heat exchangers, and the impacts of SPU on maximum system discharge temperature), and Section 2.6.1, Primary Containment Functional Design (discusses the postulated accident scenarios which use the ultimate heat sink for heat rejection).

DNC has confirmed that SPU has no adverse impact upon the engineering assessments that form the technical bases for the T/S 3.7.5, “ultimate heat sink temperature” action statement. This action statement allows for 12-hours of continued plant operation provided that the UHS temperature is reasonably expected to return below 75°F during the 12-hour period and the peak temperature remains below 77°F.

2.5.4.4.4 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the UHS. DNC concludes that the evaluation has adequately demonstrated that the design-basis safety function of the UHS will not be compromised. Based on this, the ultimate heat sink will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-5 and GDC-44. Therefore, DNC finds the proposed SPU is acceptable with respect to the ultimate heat sink.

2.5.4.5 Auxiliary Feedwater System

2.5.4.5.1 Regulatory Evaluation

In conjunction with a seismic Category I water source, the auxiliary feedwater system functions as an emergency system for the removal of heat from the primary system when the main feedwater system is not available. The auxiliary feedwater system may also be used to provide decay heat removal necessary for withstanding or coping with a station blackout. The DNC review for the proposed SPU focused on the system's continued ability to provide sufficient emergency feedwater flow at the expected conditions (e.g., steam generator pressure) to ensure adequate cooling with the increased decay heat. The DNC review also considered the effects of the proposed SPU on the likelihood of creating fluid flow instabilities (e.g., water hammer) during normal plant operation, as well as during upset or accident conditions.

The acceptance criteria for the auxiliary feedwater system are based on:

- GDC-4, insofar as it requires that structures, systems, and components important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures;
- GDC-5, insofar as it requires that structures, systems, and components important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions;
- GDC-19, insofar as it requires that equipment at appropriate locations outside the control room be provided with (a) the capability for prompt hot shutdown of the reactor, and (b) a potential capability for subsequent cold shutdown of the reactor;
- GDC-34, insofar as it requires that an residual heat removal system be provided to transfer fission product decay heat and other residual heat from the reactor core, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure; and
- GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related structures, systems, and components to a heat sink under both normal operating and accident conditions be provided, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure.

Specific review criteria are contained in SRP Section 10.4.9 and guidance is provided in Matrix 5 of Section 2.1 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 10.4.9, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 Station design regarding conformance to:

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4)

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

  Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5, Tabulation of Codes and Classifications.

  FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-5 is described in FSAR Section 3.1.2.5, Sharing of Structures, Systems and Components (Criterion 5)

  The MPS3 auxiliary feedwater system is a unit specific system that is not shared with other MPS units on the MPS site.

- GDC-19 is described in the FSAR Section 3.1.2.19, Control Room (Criterion 19)

  The auxiliary shutdown panel located in the west switchgear room has equipment, controls, and instrumentation to accomplish, in conjunction with controls and indication located on the adjacent 4160V switchgear, a prompt hot shutdown and the capability for subsequent cold shutdown of the reactor through the use of suitable procedures (FSAR Section 7.4.1.3, Control Room Evacuation).

- GDC-34 is described in the FSAR Section 3.1.2.34 Residual Heat Removal (Criterion 34)

  The residual heat removal system, in conjunction with the steam and power conversion system, is designed to transfer the fission product decay heat and other residual heat from the reactor core within acceptable limits. The transfer of the heat removal function from the steam and power conversion system to the residual heat removal system occurs when the reactor coolant system is at approximately 350°F and 375 psig.

  Suitable redundancy at temperatures below approximately 350°F is accomplished with the two residual heat removal pumps (located in separate compartments with means available for draining and monitoring of leakage), the two heat exchangers and the associated piping, cabling, and electric power sources. The residual heat removal system is able to operate on either onsite or offsite electric power system.

Suitable redundancy at temperatures above approximately 350°F is provided by the steam generators and associated piping systems.

FSAR Section 5.4.7, Residual Heat Removal System, and Chapter 10, Steam and Power Conversion System, give details of the system design.

- GDC-44 is described in FSAR Section 3.1.2.44, Cooling Water
(Criterion 44)

  The reactor plant component cooling water system, the charging pump cooling system, spent pool cooling and purification system and the safety injection pump cooling system, transfer heat from systems containing reactor coolant to the service water systems. Together these systems transfer heat to the ultimate heat sink from structures, systems and components important to safety during normal and accident conditions.

  These systems are designed with suitable redundancy in components, with leak protection, and with the capability to isolate redundant components. The systems are designed to satisfy the cooling water requirements assuming a single failure and either a loss of onsite or offsite power.

Additional details that define the licensing basis for the auxiliary feedwater system are described in FSAR Section 10.4.9, Auxiliary Feedwater System.

FSAR Section 15, Accident Analyses, describes how the auxiliary feedwater system is credited in the mitigation of transients and accident conditions.

Technical Specification 3/4.7.1.2, Auxiliary Feedwater System, ensures a makeup water supply to the steam generators to support decay heat removal from the reactor coolant system to mitigate the consequences of numerous design basis accidents, including feedwater line break, loss of normal feedwater, steam generator tube rupture, main steam line break, and small break loss of coolant accident.

FSAR Section 10.4.9.1 and Technical Specification 3/4.7.1.3, Demineralized Water Storage Tank, require an adequate supply of makeup water to the steam generators to maintain the reactor coolant system in hot standby for 10 hours with steam discharge to the atmosphere, concurrent with a total loss-of-offsite power, and with an additional 6 hour cooldown period to reduce reactor coolant temperature to 350°F.

Technical Specification 3/4.6.3, Containment Isolation Valves, ensures isolation of containment penetrations in support of containment isolation.

The auxiliary feedwater system was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, dated August 1, 2005 documents the results of that review. NUREG-1838, Sections 2.3B.4.5 and 3.4B are applicable to the auxiliary feedwater system.

2.5.4.5.2 Technical Evaluation

2.5.4.5.2.1 Introduction

The auxiliary feedwater system ensures a makeup water supply to the steam generator secondary side to support decay and sensible heat removal for the reactor coolant system. The auxiliary feedwater system is designed to mitigate many accidents, including the loss of normal feedwater, feedwater line break, steam generator tube rupture, steam line break, small break loss of coolant accidents, etc. The auxiliary feedwater system also supports the heat removal design function for other events of regulatory significance such as station blackout, anticipated transient without trip, safety grade cold shutdown, fire shutdown, high energy line break shutdown, etc. The auxiliary feedwater system normally operates to support plant startup, hot standby and shutdown evolutions.

The auxiliary feedwater system consists of two half capacity motor driven auxiliary feedwater pumps, one full capacity turbine driven auxiliary feedwater pump, demineralized water storage tank and associated piping and valves. The motor driven AFW pump can be in normal service to support normal startup, hot-standby, and shutdown operation and therefore, portions of the AFW Systems are classified as high energy lines in accordance with SRP 3.6.1/3.6.2.

2.5.4.5.2.2 Description and Evaluation

The auxiliary feedwater system and associated components were evaluated to ensure intended functions are performed at SPU conditions. The evaluations compared the existing design parameters of the systems/components with the SPU conditions in conjunction with the following design aspects:

- Design versus operating pressure/temperature of piping and components
- Required flow rates/pump capabilities
- Containment Isolation Capabilities
- Water supplies/sources
- Pump design and performance

The primary impact of the SPU on the auxiliary feedwater system is the increased core thermal power and the resulting higher heat removal requirements during design basis events/accidents, normal cooldown, and safety grade cold shutdown.

A licensing basis change is proposed as part of SPU to addresses the higher decay heat. The revised licensing basis will ensure sufficient water is available to maintain the reactor coolant system at hot standby for 7 hours with steam discharge to the atmosphere, concurrent with a total loss of offsite power, and with an additional 6 hour cooldown period to reduce reactor coolant temperature to 350°F. The new demineralized water storage tank sizing criterion ensures adequate inventory to support safety grade cold shutdown as demonstrated by Table 2.5.4.5-1 and Table 2.5.4.5-2. Thus, there is no change in the degree of compliance to BTP RSB 5-1 due to this change. This change is also acceptable relative to station blackout, fire shutdown (see

Table 2.5.4.5-3 and Section 2.5.1.4), and other functional requirements derived from the safety analysis (see Section 2.8.5).

Other evaluations of the auxiliary feedwater system, piping and components are addressed in the following Licensing Report sections:

- Piping/component supports and water hammer effects – Section 2.2.2.2, Balance of Plant Piping and Supports (Non-Class 1)
- Operation of the auxiliary feedwater system during postulated abnormal and accident scenarios is discussed in Section 2.8.5, Accident and Transient Analyses
- Protection against dynamic effects, including GDC-4 requirements, of missiles, pipe whip and discharging fluids - Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects
- Environmental qualification – Section 2.3.1, Environmental Qualification of Electrical Equipment
- Safety related valve and pump testing and valve closure, including containment isolation requirements – Section 2.2.4, Safety-Related Valves and Pumps

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the proposed SPU on the conclusions reached in the MPS3 License Renewal Safety Evaluation Report for the auxiliary feedwater system. As stated in Section 2.5.4.5.1, the auxiliary feedwater system is within the scope of License Renewal. SPU activities will not add any new components nor introduce any new functions for existing components that would change the license renewal evaluation boundaries. There are no changes associated with operation of the auxiliary feedwater system at SPU conditions and the proposed SPU does not add any new or previously unevaluated materials to the auxiliary feedwater system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.4.5.2.3 Results

The higher heat removal requirements during normal, abnormal, and accident conditions do not change the maximum system operating conditions with implementation of the proposed SPU, or margins to auxiliary feedwater system piping and components design. As such, auxiliary feedwater system piping and components are acceptable for SPU operation. Since there are no minimum or maximum available flow changes with SPU the likelihood of fluid flow instabilities is not increased with SPU.

SPU analyses have demonstrated adequate AFW System flow capability for:

1. FSAR Section 15 accidents
2. Functional requirements derived from station blackout, ATWS, safety grade cold shutdown, fire shutdown, HELB safe shutdown
3. Functional requirement inherent in the AFW System reliability analysis

4. Normal shutdown, hot-standby, startup support

Table 2.5.4.5-4 provides supporting information for the above conclusion. Additionally, the demineralized water storage tank contains sufficient usable volume based on the existing Technical Specification 3.7.1.3, Limiting Conditions of Operation, to support auxiliary feedwater system operation after implementation of the proposed SPU.

The auxiliary feedwater system will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-2, as the proposed SPU will not impact the system capability to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, and floods.

A licensing basis change is proposed as part of SPU to addresses the higher decay heat such that sufficient water will be available to maintain the reactor coolant system at hot standby for 7 hours with steam discharge to the atmosphere, concurrent with a total loss of offsite power, and with an additional 6 hour cooldown period to reduce reactor coolant temperature to residual heat removal system entry conditions.

The auxiliary feedwater piping located inside containment remains qualified for the peak containment temperature.

The auxiliary feedwater system's containment automatic isolation valves are capable of supporting the containment isolation function after SPU.

Analysis has demonstrated at least 10 minutes are available for operator action when operating below 10 percent Rated Thermal Power such that T/S 3.7.1.2 "above 10 percent RATED THERMAL POWER" criterion technical bases remains valid for SPU.

SPU has no adverse impact upon the AFW System HELB design or the plant's capacity to reach cold shutdown conditions following an AFW HELB event in accordance with SRP 3.6.1/3.6.2.

The AFW System has design features that provide the capability for the AFW pumps to take suction from condensate storage tank or the service water system. SPU has no adverse impact on these design features.

The conclusions of the existing reliability analysis of the auxiliary feedwater system, which demonstrate system reliability within the acceptance criteria of SRP 10.4.9, are unchanged by the proposed SPU.

The instrument ranges and setpoints associated with auxiliary feedwater system instrumentation and control components, which include RG 1.97 instrumentation, do not require change for implementation of the proposed SPU.

SPU has no impact on the AFW System's degree of compliance to RG 1.62 specified in FSAR Table 1.8-1.

2.5.4.5.3 Conclusion

The DNC evaluation has adequately accounted for the effects of the increase in decay heat and other changes in plant conditions on the ability of the auxiliary feedwater system to supply adequate water to the steam generators to ensure adequate cooling of the core. The auxiliary feedwater system will continue to meet its design functions following implementation of the proposed SPU. The auxiliary feedwater system will also continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-4, GDC-5, GDC-19, GDC-34, and GDC-44. Therefore, DNC finds the proposed SPU is acceptable with respect to the auxiliary feedwater system.

Table 2.5.4.5-1
Technical Specification 3.7.1.3 - Demineralized Water Storage Tank Comparison Before and After SPU

Parameter	**Current Design**	**SPU**	**Comment**
Limiting Condition of Operation - Required Measured Inventory (gallons)	334,000	334,000	
Tech Spec Bases (hours)	10/6	7/6	See Note 1
Required Inventory for Decay and Sensible Heat Removal (gallons)	314,636	307,082	See Note 2
Required for Unusable Inventory Due to Tank Geometry/Vortexing (gallons)	13,570	13,570	
Measurement Uncertainty Allowance (gallons)	5,734	5,734	
Required Inventory Subtotal (gallons)	333,940	326,386	
Margin Between LCO and Tech Spec Bases Inventory Requirement (gallons)	60	7614	
Other Information			
Decay Heat – ANSI/ANS 5.1-1979 with 2σ uncertainty, based upon 102% licensed power level	Yes	Yes	
DWST Temperature (°F)	120	120	
Note 1 -Hot standby/cooldown to residual heat removal entry conditions under natural circulation conditions, including an allowance for tank inventory not usable because of tank discharge line location, other tank physical characteristics, and surveillance measurement uncertainty, plus an allowance for 30-minute spillage due to a feedwater line break. **Note 2** –Includes SG-refill, feedwater line spillage, and calculational uncertainty allowances.			

Table 2.5.4.5-2
Demineralized Water Storage Tank - SGCS Functional Requirements Comparison Before and After Uprate

Parameter	Current Design	SPUP	Comment
Required Inventory for Decay and Sensible Heat Removal (gallons)	229,742	256,811	
Allowance for SG refill, non-seismic line break spillage, and calculation uncertainty (gallons)	36,722	39,270	
Required Inventory for Unusable Inventory Due to Tank Geometry/Vortexing (gallons)	13,570	13,570	
Measurement Uncertainty Allowance (gallons)	5,734	5,734	
Required Measured DWST Inventory for SGCS (gallons)	285,768	315,385	
Margin - T/S 3.7.1.3 LCO To SGCS Inventory Requirement (gallons)	48,232	18,615	
T/S 3.7.1.3 LCO Bounding	Yes	Yes	
Other Information			
Decay Heat – ANSI/ANS 5.1-1979, with 2σ uncertainty, based upon 102% licensed power level	Yes	Yes	
DWST Temperature (°F)	120	120	
RHR Entry Time (hr) [after reactor trip]	11	11	
Note 1 – This inventory is based upon a 6-hour hot-standby duration, followed by a 5-hour cooldown to RHR entry conditions.			

Table 2.5.4.5-3 Demineralized Water Storage Tank – Fire Shutdown Functional Requirements Comparison Before and After Uprate

Parameter	Current Design	SPUP	Comment
DWST and CST With A Combined Usable Inventory Equivalent To: (hours)	38/5 (43 total)	28/5 (33 total)	See Notes 1 & 2
Other Information			
Decay Heat – ANSI/ANS 5.1-1979, with 2σ uncertainty, based upon 102% licensed power level	Yes	Yes	
DWST Temperature (°F)	120	120	
Note 1 - Hot standby/RCS cooldown to RHR entry conditions under natural circulation conditions. **Note 2** – See Section 2.5.1.4 for details and supporting assessment.			

Table 2.5.4.5-4
Margin Between Nominal Calculated Minimum Available AFW Flow Rate And That Used Within Various Analyses Comparison Before and After Uprate

Analysis	Current Design (%)	SPUP (%)	Comment
FSAR Section 15			
Loss of Normal Feedwater Analysis/Loss of AC Power	17	12	Note 1
Feedwater Line Break Analysis	12	12	Note 1
SGTR	17	12	Note 1
SBLOCA (offsite dose analysis, minimum flow)	17	12	Note 2
ATWS	12	12	Note 1
Other Analyses			
Better Estimate Loss of Normal Feedwater Analysis (reliability support analysis)	5.24	2.5	Note 3

Note 1 – The safety analysis uses a delivered AFW flow versus SG operating pressure curve. The calculation uncertainty in available AFW flows is less than 5.24%. Therefore, there is significant margin maintained between minimum available AFW flow and that assumed in the safety analysis.

Note 2 – The SBLOCA uses one specific data point derived from a delivered AFW flow versus SG operating pressure curve. This flow is derived from the less 12% curve.

Note 3 – This reliability support analysis uses a best estimate methodology. This analysis also uses a delivered AFW flow versus SG operating pressure curve.

2.5.5 Balance-of-Plant Systems

2.5.5.1 Main Steam

2.5.5.1.1 Regulatory Evaluation

The main steam supply system transports steam from the NSSS to the power conversion system and various safety-related and non-safety-related auxiliaries. The DNC review focused on the effects of the proposed SPU on the system's capability to transport steam to the power conversion system, provide heat sink capacity, supply steam to drive safety system pumps, and withstand adverse dynamic loads (e.g., steam hammer resulting from rapid valve closure and relief valve fluid discharge loads).

The acceptance criteria for the main steam supply system are based on:

- GDC-4, insofar as it requires that structures, systems, and components important-to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures
- GDC-5, insofar as it requires that structures, systems, and components important-to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions
- GDC-34, insofar as it requires that a residual heat removal system be provided to transfer fission product decay heat and other residual heat from the reactor core.

Specific review criteria are contained in SRP Section 10.3 and guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 10.3, Rev. 2. MPS3 took the following exception to this SRP:

- FSAR does not tabulate and describe all flow paths that branch off the main steam lines between the main steam isolation valves and the turbine stop valves

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design regarding conformance to:

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4)

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5, Tabulation of Codes and Classifications.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-5 is described in FSAR Section 3.1.2.5, Sharing of Structures, Systems and Components (Criterion 5)

  The MPS3 main steam system is a unit specific system that is not shared with MPS2.

- GDC-34 is described in the FSAR Section 3.1.2.34, Residual Heat Removal (Criterion 34)

  The residual heat removal system, in conjunction with the steam and power conversion system, is designed to transfer the fission product decay heat and other residual heat from the reactor core within acceptable limits. The transfer of the heat removal function from the steam and power conversion system to the residual heat removal system occurs when the reactor coolant system is at approximately 350°F and 375 psig.

  Suitable redundancy at temperatures above approximately 350°F is provided by the steam generators and associated piping system.

  FSAR Chapter 10, Steam and Power Conversion System, documents details of the system design.

Additional details that define the licensing basis for the main steam system are described in:

- FSAR Section 5.4.4, Main Steam Line Flow Restrictor
- FSAR Section 6.2.4, Containment Isolation System

Technical Specification 3/4.7.1.1, Safety Valves, ensures all main steam line code safety valves be operable with lift settings as specified in Table 3.7-3.

Technical Specification 3/4.7.1.5, Main Steam Isolation Valves, ensures the operability of main steam isolation valves.

Technical Specification 3/4.7.1.6 ensures the operability of each steam generator atmospheric relief bypass valve line.

The main steam system was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Unit 2 and 3, date published October, 2005 documents the results of that review. NUREG-1838 Sections 2.3B.4.1 and 3.4B are applicable to the main steam system.

2.5.5.1.2 Technical Evaluation

2.5.5.1.2.1 Introduction

The main steam system is described in FSAR Section 10.3. The main steam system transports steam from the steam generators to the power conversion systems. This system provides a means of controlled heat release from the nuclear steam supply system during periods of station electrical load rejection or when the condenser is not available. The system also provides motive steam to the steam generator feedwater pump turbines (during startup) and steam generator auxiliary feedwater pump turbine, and steam for various auxiliary services including turbine gland sealing and the auxiliary steam system.

The main steam system is designed to transport dry saturated steam produced in the steam generators to the high pressure turbine, as well as other steam driven components and auxiliary systems. The main steam system includes the steam piping, main steam safety valves, main steam pressure relieving valves, main steam pressure relieving bypass valves, main steam isolation trip valves, main steam flow restrictors and other miscellaneous valves and piping.

The main steam system also provides a flow path for steam from the steam generators to the turbine bypass system, which is discussed in Section 2.5.5.3, Turbine Bypass.

The reheat (cold and hot) steam system is considered a part of the main steam system for the MPS3. The reheat (cold and hot) system delivers steam from the high pressure turbine exhaust through the moisture separator reheaters and then to the low pressure turbine inlets. The system is designed to remove up to 92 percent of the moisture from the high pressure turbine exhaust in the chevron type baffles and then reheat the exhaust to super heated conditions (using main steam) in the moisture separator reheaters and send the steam to the low pressure turbines. The reheat system includes the moisture separator reheaters, cross-around relief valves, miscellaneous valves and the piping associated with this equipment.

The main steam system design functions are:

- Supply steam from the steam generators to the main turbine, steam generator feedwater pump turbines (during startup), steam generator auxiliary feedwater pump turbine, moisture separator reheaters, turbine gland sealing system, condenser air ejectors, main steam pressure relieving valves, main steam pressure relieving bypass valves and steam dump (turbine bypass) system
- Control steam generator pressure by atmospheric steam dump when the condenser is not available
- Provide over-pressure protection for the steam generators and main steam piping
- Provide a primary containment isolation boundary
- Provide for main steam line and turbine warm-up
- Provide a means to dissipate the heat generated in the Nuclear Steam Supply System during all modes of normal operation, transient and accident conditions

The reheat steam system design functions are:

- Moisture removal and reheating of steam from the high pressure turbine exhaust via moisture separator reheaters
- Supply superheated steam from the moisture separator reheaters to the low pressure turbines
- Provide over-pressure protection for the moisture separator reheater and reheat piping
- Supply hot reheat steam to the steam generator feedwater pump turbines

2.5.5.1.2.2 Description of Analyses and Evaluations

The main steam and reheat steam systems and components were evaluated to ensure they are capable of performing their intended functions at SPU conditions. The evaluations were conservatively performed for an analyzed NSSS thermal power of 3666 MWt. The evaluations compared the existing design parameters of the systems/components with SPU conditions for the following design aspects:

- System operating parameters – current versus SPU
- System/Component design pressures/temperatures versus SPU conditions
- Piping flow velocities
- Piping vibration
- Steam hammer
- Capacity and setpoints of the main steam safety valves, main steam pressure relieving valves, main steam pressure relieving bypass valves and cross-around relief valves
- Main turbine stop, control, and combined intercept valves
- Closure times for the main steam isolation trip valves and main steam isolation trip valve bypass valves
- Stroke times for the auxiliary feedwater pump turbine steam supply air operated valves and auxiliary feedwater pump turbine exhaust pipe drain valve
- Operability of the steam generator feedwater pump turbines and steam generator auxiliary feedwater pump turbine
- Overspeed protection for the main turbine and steam generator feedwater pump turbines
- Moisture separator reheaters' design, operation, and performance in regards to the following:
  - Shell and tube side design pressures/temperatures versus SPU conditions
  - Steam flow capacity and pressure setting of the cross-around piping self-actuated safety valve systems; including effect of reheater tube rupture on the safety relief valve steam flow capacity
  - Vibration

   - Changes in moisture separation, superheat temperature (or terminal temperature difference changes) and pressure drop
   - Combined intercept valve testing
   - Shell drain system capacity
   - Excess steam venting system capacity
   - Flow accelerated corrosion
- Main steam supply for auxiliary services
- Main steam piping drain pipe capacity

A review of available industry operating experience related to the Main Steam system was also performed.

Other evaluations of main steam and reheat steam systems and components are addressed in the following sections:

- Section 2.5.5.3, Turbine Bypass, which discusses the SPU evaluations of main steam piping/components supporting turbine bypass operations
- Section 2.1.8, Flow-Accelerated Corrosion, which discusses the effects of increased flow and velocity with SPU on the corrosion of main steam piping/components
- Section 2.2.2.2, Balance of Plant Piping and Supports (Non-Class 1), which discusses the impact of SPU on the capability of main steam piping to withstand adverse dynamic loads

Impact on Renewed Plant Operating License and License Renewal Programs

DNC has evaluated the SPU impact on the conclusion reached in the MPS3 license renewal Safety Evaluation Report (NUREG-1838) for the main steam system. As stated in Section 2.5.5.1.1, portions of the main steam system are within the scope of License Renewal. With the exception of the steam generator feedwater pump turbine modifications, for which implementation will consider the impacts on aging management programs through the design change process, SPU activities are not adding any new components within the existing license renewal scoping evaluation boundaries. No SPU activities introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Additionally, the changes associated with operating the main steam system at SPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. A review of internal and industry operating experience has not identified the need to modify the basis for aging management programs to account for the effects of SPU.

2.5.5.1.2.3 Results

System Operating Parameters – Current Versus SPU

Heat balances were developed to determine the steam cycle parameters while operating at the increased NSSS power level. Heat balances were developed for the current power level based on actual plant operating data and at the analyzed SPU NSSS thermal power of 3666 MWt.

Current and SPU main steam, cold reheat and hot reheat conditions are listed in Table 2.5.5.1-1 for the purpose of comparison.

System/Component Design Pressure/Temperature Versus SPU

The existing system design pressures for the main steam (1185 psig), and cold and hot reheat steam (250 psig) systems are bounding for SPU operations as the capability of system overpressure protection will be unchanged by the proposed SPU. Additionally, the existing system design temperatures for the main steam system (600°F) and the cold reheat lines (500°F) remain bounding for SPU conditions as they are higher than the saturation temperatures associated with no-load and piping design pressures, which are unchanged by the proposed SPU.

The system design temperature of the hot reheat lines (500°F), which includes the supply lines to the steam generator feedwater pump turbines, will be rerated for maximum SPU operating conditions (533°F). These lines, however, are acceptable for SPU operations based on the maximum allowable stress values of the piping materials.

The existing main steam and cold reheat piping designs are acceptable for SPU operation as system design pressures and temperatures are unchanged by the proposed SPU. Similarly, the existing design pressure of the hot reheat piping (includes supply lines to the steam generator feedwater pump turbines) is acceptable for SPU operation. As noted above the design temperature for these lines will be rerated for maximum SPU operating conditions, however, these lines are acceptable for SPU operations based on the maximum allowable stress values of the piping materials.

The existing design parameters or pressure ratings of all main steam, cold reheat, and hot reheat valves were reviewed and are equal to or are bounded by system design pressures and temperatures (1185 psig and 600°F for main steam, 250 psig and 500°F for reheat steam) and maximum SPU conditions.

Piping Flow Velocities

Flow velocities through the main steam, cold reheat and hot reheat piping were calculated for SPU conditions. These flow velocities, which increased approximately 8.5 percent primarily due to the increased flows required for SPU operation, are bound by the industry design guidelines. Refer to Table 2.5.5.1-2.

The DNC flow accelerated corrosion program currently monitors the main steam, cold reheat and hot reheat piping. Based on the flow velocity increases with SPU, the potential for flow accelerated corrosion is essentially unchanged by the proposed SPU. Present monitoring activities will be continued after implementation of the proposed SPU. Refer also to Section 2.1.8, Flow-Accelerated Corrosion.

Piping Vibration

The increased steam flow velocities with SPU through piping and components has the potential to increase vibrations. Accordingly, during power ascension following implementation of the proposed SPU, piping will be monitored to identify line vibration anomalies. These vibration monitoring activities are discussed in Section 2.12, Power Ascension and Testing Plan.

Steam Hammer

The capability of the main steam system to withstand adverse dynamic loads (e.g., steam hammer resulting from rapid valve closure and relief valve discharge loads) at SPU conditions is addressed in Section 2.2.2.2, Balance of Plant Piping and Supports (Non-Class 1).

Main Steam Valve Capacities and Setpoints

Main Steam Safety Valves

The existing set pressures of the main steam safety valves are based on the design pressure of the steam generators and main steam piping and the requirements of the ASME III Boiler and Pressure Vessel (B&PV) Code. As these design parameters are unchanged by the proposed SPU, the existing set pressures are acceptable for SPU operation.

The main steam safety valves were sized to pass 105 percent of the maximum calculated main steam flow at an accumulation pressure not exceeding 110 percent of the main steam system design pressure. SPU evaluations demonstrate that the capacity of the installed main steam safety valves satisfies the sizing criterion, and overpressure protection requirements for the range of SPU NSSS design parameters.

The main steam safety valves' design bases includes a maximum flow limit per valve of 970,000 lb/hr at 1185 psig to preclude an uncontrolled plant cooldown and corresponding excessive reactivity excursion. As these valves are unchanged by the proposed SPU, the actual capacity of any single main steam safety valve is less than the maximum flow limit per valve, and the maximum capacity criterion is satisfied.

Main Steam Pressure Relieving Valves

The main steam pressure relieving valves automatically open and exhaust to atmosphere whenever the steam line pressure exceeds a predetermined set point to minimize main steam safety valve lifting during steam pressure transients. As the line pressure decreases, these valves close and reseat at a pressure below the opening pressure. The existing set pressure of these valves (1125 psig), which is based on steam generator zero-load steam pressure and the set pressure of the lowest-set main steam safety valve, is acceptable for SPU operations as these pressures are unchanged by the proposed SPU.

The main steam pressure relieving valves were sized to pass approximately 15 percent of rated main steam flow at no-load pressure. SPU evaluations demonstrate the total installed capacity supports plant cooldown capability for the range of NSSS design parameters approved for the proposed SPU.

The main steam pressure relieving valves' design bases includes a maximum flow limit per valve of 970,000 lb/hr at 1185 psig to preclude an uncontrolled plant cooldown and corresponding excessive reactivity excursion. As these valves are unchanged by the proposed SPU, the actual capacity of any single pressure relieving valve is less than the maximum flow limit per valve, and the maximum capacity criterion is satisfied.

Main Steam Pressure Relieving Bypass Valves

SPU evaluations demonstrate existing main steam pressure relieving bypass valve flow capability satisfies the design basis functional requirements inherent in the FSAR Chapter 15 safety analyses, the safety grade cold shutdown analysis, and the fire shutdown cooldown analysis.

Cross-Around Relief Valves

The existing set pressure range of the cross-around relief valves is acceptable for SPU operations as it is based on the cross-around piping design pressure, which is unchanged by the proposed SPU. The minimum set pressure of these valves is greater than the maximum SPU high pressure turbine exhaust pressure by approximately 20 percent. Additionally, the estimated blowdown pressure of these valves is greater than the minimum operating pressure at the combined intercept valve inlets during SPU operation.

SPU evaluations demonstrate the cross-around piping relief valves have the capability to pass SPU full load steam flow to provide overpressure protection of piping and moisture separator reheater without exceeding 116 percent of design pressure to be in accordance with the requirements of Section UG-125(c) (1) of ASME VIII.

Main Turbine Stop, Control, and Combined Intercept Valves

The steam flow velocity at the inlet of the main stop valves, at the throat of the control valves, and at the inlet/outlet of the combined intercept valves are within the design limits during SPU operation.

Main Steam Isolation Trip Valves and Main Steam Isolation Trip Valve Bypass Valves

The main steam isolation trip valves are not adversely affected in the open position during normal full power SPU operation. These valves will close within the current required time period during accident conditions.

The added pressure drop through the main steam isolation trip valves at SPU flow rates has been included in establishing the main steam supply pressure at the HP turbine inlet; thus ensuring acceptable steam pressure for SPU full power generation.

The closure time of the main steam isolation trip valves is not affected at SPU since the valve and operator designs are based on the flow rate due to the worst case break flow that the valve experiences. The proposed SPU does not affect the pipe break flows since the factors that affect maximum possible break flow are not affected by the proposed SPU.

The main steam isolation trip valve bypass valves are provided to permit equalizing steam pressure across the main steam isolation trip valves prior to opening or to provide steam for line warming and auxiliary services during plant startup. This valve must also respond to limit the effects of main steam and feedwater line breaks as specified for main steam isolation trip valves. The required time to close is not affected by increased flow at SPU as the worst case break flow the valves experience is not affected by the proposed SPU.

Auxiliary Feedwater Pump Turbine Steam Supply/Exhaust Valves

As the existing steam generator no-load pressure, lowest main steam safety valve set pressure, and the set pressure of main steam pressure relieving valves are unchanged for SPU operation, and the changes in steam supply flow velocities and pressure drops with SPU are not significant, these valves will satisfy the allowable stroke time requirements after implementation of the proposed SPU.

The auxiliary feedwater pump turbine exhaust pipe drain valve is normally open to drain the condensed steam from the exhaust piping during auxiliary feedwater pump/ turbine testing to prevent water from accumulating in the exhaust line and potentially collecting in the turbine casing. This valve closes automatically by the opening any one of three (3) main steam supply valves to the turbine. Since there is no change in exhaust line conditions at SPU, the valve will continue to meet the allowable stroke time requirement.

Steam Generator Feedwater Pump Turbine and Steam Generator Auxiliary Feedwater Pump Turbine

Evaluations demonstrate the steam generator feedwater pump turbines are capable of providing motive power (HP) and required speed to the steam generator feedwater pumps to provide the required feedwater flow and pressure to steam generators at SPU conditions with modifications. To preclude any problems with design capability and performance at SPU conditions, the entire turbine steam path including the rotating assembly and the diaphragms will be replaced.

The results of SPU safety analyses confirms the existing auxiliary feedwater system arrangement/performance remain bounding at SPU conditions in terms of providing flow and pressure to mitigate the consequences of the design basis events/accidents. Hence, the existing steam generator auxiliary feedwater pump turbine is capable of providing motive power (HP) and required speed to the steam generator feedwater pump to provide the required flow and pressure to steam generators at SPU operation. Refer also to Section 2.5.4.5, Auxiliary Feedwater System.

Turbine Driven Feedwater Pump Turbine Control Valves

The engineering evaluation to confirm whether or not more steam flow is required for turbine driven feedwater pump turbines for SPU conditions is in progress. There is a potential for the control valve and/or seat modifications to provide more steam flow to the turbine driven feed pump steam control valves.

Overspeed Protection

There is no change to the rotating elements or entrained steam volume associated with the main turbine as result of the proposed SPU. Therefore, no changes to the overspeed trip controls are required.

Based on the current high speed stop setting, mechanical trip (i.e., emergency overspeed) setting, and the marginal increase in maximum operating speed of steam generator feedwater pump turbines with implementation of the proposed SPU (one pump/turbine in operation), the current emergency overspeed governor is sufficient for SPU operation.

Moisture Separator Reheaters

The moisture separator reheaters were evaluated for SPU operation based on current design, materials, construction, and performance. Current plant operating and inspection data, and the predicted SPU heat balance conditions were utilized in these evaluations.

As the reheat system overpressure protection is unchanged by the proposed SPU, the existing moisture separator reheater shell side design pressure (270 psig) is acceptable for SPU operation. Additionally, the existing shell side design temperature (650°F), which is bounded by the main steam system design temperature and SPU conditions, is acceptable for SPU operation.

The existing moisture separator reheaters' tube side design pressure (1185 psig) is acceptable for SPU operation since it is equal to the main steam system design pressure. Additionally, the existing moisture separator reheaters' tube side design temperature (572°F) is acceptable for SPU operation since it bounds the maximum moisture separator reheater outlet steam temperature for SPU operation (533°F).

Additional evaluations concluded:

- The reheater bundles are likely to endure vibration excitation due to higher flow velocities without failure,
- Slightly lower performance at SPU conditions will cause a minor negative effect on the plant heat rate and will have minimum impact on the expected reliability of the low pressure turbines
- The internal drain system is found to be sufficient at SPU conditions
- Review of moisture separator reheater construction and related calculations concludes no action is required beyond visual inspection for flow accelerated corrosion

Main Steam Supply for Auxiliary Services

The main steam system ability to supply steam to other auxiliary systems/components (e.g., gland sealing steam, main condenser air ejectors, auxiliary steam system) is not affected by implementation of the proposed SPU since the steam flow requirements are insignificant as compared to the entire main steam system flow. SPU heat balances include these auxiliary flows, and confirm sufficient main steam flow exists to ensure the high pressure turbine and moisture separator reheaters performance supports SPU operation.

Main Steam Piping Drain Pipe Capacity

The main steam and hot reheat steam piping to steam generator feedwater pump turbines are provided with the drain lines to collect water from condensing steam in the piping and direct the water to the condenser hotwell.

The drain lines current design provides sufficient capacity based for start-up when hot steam is introduced into cold piping. This startup situation typically produces more water from steam than is produced during normal operating conditions when both the incoming steam and the piping are hot. Since the start-up conditions are not affected by the proposed SPU, this drain line sizing is unaffected.

Industry Operating Experiences

The Industry Operating Experiences pertaining to the MPS3 Main Steam System relates to the following subject areas:

- Main Steam Lines, Valves and Connected Lines Experiencing Elevated Vibrations and Associated Equipment Failures
- I&C Setpoint Margin and Drift
- Over-ranging transmitters and over-ranging the capacity of attached components such as transmitters and valves.

Refer to the discussion in this section with respect to vibration and flow accelerated corrosion under caption Piping Flow Velocities, Piping Vibration, and Moisture Separator Reheaters.

The margin between SPU operating pressure/temperature/flow and I & C setpoint margin was evaluated and determined to be adequate to prevent the encroachment by instrumentation drift and other calibration issues. In most cases the SPU Main Steam System pressures/ flows/ temperatures are bounded by the current calibrated range of instrumentation. The moisture separator reheater steam supply flow instrument loops and turbine control pressure instrumentation however will be rescaled to accommodate the increased flow rate and pressure in accordance with the plant design change process. See Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems for details.

2.5.5.1.3 Conclusion

DNC has reviewed the evaluation of the effects of the proposed SPU on the main steam system. DNC concludes that the evaluation has adequately accounted for the effects of changes in plant conditions due to the proposed SPU on the design of the system. DNC concludes the main steam pressure relieving bypass valves will continue to provide a means for shutting down the plant in the safety grade shutdown scenario. DNC further concludes that the main steam supply system will maintain its ability to transport steam to the power conversion system, provide heat sink capacity, supply steam to steam-driven safety pumps, and withstand steam hammer. DNC further concludes that the main steam supply system will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-4, GDC-5 and GDC-34 and NUREG-0800, SRP Section 10.3, Rev. 2. Therefore, DNC finds the proposed SPU is acceptable with respect to the main steam supply system.

Table 2.5.5.1-1
Current and SPU Main Steam, Cold Reheat, and Hot Reheat Data Comparison

Parameters	Current Operating Conditions 55.5°F CWT	SPU Operating Conditions 55.5°F CWT 0.6% SGTP	SPU Operating Conditions 55.5°F CWT 10% SGTP
Main Steam – Steam Generator Outlets			
Flow Rate, lb/hr	15,012,100	16,266,524	16,252,016
Pressure, psia	997	994	973
Temperature, °F	544	544	541
Main Steam- Main Steam to HP Turbine			
Flow Rate, lb/hr	13,437,299	14,617,547	14,634,498
Pressure, psia	973	966	944
Temperature, °F	541	540	538
Main Steam- Heating Steam to Moisture Separator Reheaters			
Flow Rate, lb/hr	1,572,151	1,646,327	1,614,868
Pressure, psia	973	966	945
Temperature, °F	541	540	538
Cold Reheat Steam- Moisture Separator Reheater Inlet			
Flow Rate, lb/hr	11,802,394	12,777,212	12,783,367
Pressure, psia	170	184	185
Temperature, °F	369	375	375
Hot Reheat Steam- Moisture Separator Reheater Outlet			
Flow Rate, lb/hr	10,285,638	11,155,196	11,183,215
Pressure, psia	166	180	180
Temperature, °F	535	533	531
Hot Reheat Steam- Hot Reheat Steam to LP Turbines			
Flow Rate, lb/hr	10,090,120	10,943,696	10.971,569
Pressure, psia	166	180	180
Temperature, °F	535	533	531

Table 2.5.5.1-1
Current and SPU Main Steam, Cold Reheat, and Hot Reheat Data Comparison

Parameters	Current Operating Conditions 55.5°F CWT	SPU Operating Conditions 55.5°F CWT 0.6% SGTP	SPU Operating Conditions 55.5°F CWT 10% SGTP
Hot Reheat Steam- Hot Reheat to Steam Generator Feedwater Pump Turbines			
Flow Rate, lb/hr	195,517	211,500	211,646
Pressure, psia	162	176	176
Temperature, ºF	534	533	530

Table 2.5.5.1-2
SPU Main Steam, Cold Reheat & Hot Reheat Steam Piping Velocities

Piping Portion	Nominal Pipe Size (inch)/ Number of Pipes	Calculated Flow Velocities (ft/sec)	Industry Design Guidelines (see note below) (ft/sec)
Main Steam Piping from Steam Generator Outlets to Main Steam Manifold	30 (OD)/4	126	167
Main Steam Manifold	42.25 (OD)/1	43	167
Main Steam Piping from Main Steam Manifold to High Pressure Stop Valves	30 (OD)/3	155	167
Main Steam Piping from Main Steam Manifold to Moisture Separator Reheaters	16/2	100	167
Cold Reheat Piping from High Pressure Turbine Exhaust to Moisture Separator Reheaters	42 (OD)/8	106	167
Hot Reheat Piping from Moisture Separator Reheater to Low Pressure Turbine Combined Intercept Valves	42 (OD)/6	181	333
Hot Reheat Steam Piping to Steam Generator Feedwater Pump Turbines Stop Valves	16/1	155	333
	12/2	147	333
Main Steam Piping to Steam Generator Auxiliary Feedwater Pump turbine Stop Valve	3/3	35	167
	3/1	104	167
Note: Industry design guidelines are obtained from Crane Technical Paper 410.			

2.5.5.2 Main Condenser

2.5.5.2.1 Regulatory Evaluation

The main condenser is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system. Additional performance requirements include detecting and controlling excessive radioactive releases to the environment and system failures do not cause unacceptable condensate quality or flooding of areas housing safety-related equipment. The DNC review focused on the effects of the proposed SPU on the criteria above and the condenser's ability to accommodate the higher heat removal requirements of the turbine exhaust steam flow. The review also focused on the steam bypass following a load rejection assumption, and on the ability of the main condenser system to withstand the blowdown effects of steam from the turbine bypass system.

The acceptance criteria for this review are:

- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive materials in effluents to the environment.

Specific review criteria are contained in SRP Section 10.4.1 and guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 10.4.1, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 Station design relative to conformance to:

- GDC-60 is described in FSAR Section 3.1.2.60, Control of Releases of Radioactive Materials to the Environment (Criterion 60)

As described in this FSAR section, in all cases the design for radioactivity control is based on:

- The requirements of 10 CFR 20, 10 CFR 50, and 10 CFR 50, Appendix I, for normal operations and for any transient situation that might reasonably be anticipated to occur.
- 10 CFR 50.67 dose level guidelines for potential accidents of extremely low probability of occurrence.

  All releases paths, including ventilation and process streams are monitored and controlled as described in FSAR Section 11.5, Process, Effluent and Airborne Radiation Monitoring Systems.

  Radioactive gaseous waste effluent activity levels are monitored subsequent to release through the Millstone 375 foot stack. Under conditions of concurrent fuel failure and steam generator tube leakage, radioactive gas, if present, will be suitably controlled in the steam jet air ejector discharge in the Main Condenser Evacuation System.

Control of liquid waste effluents (FSAR Section 11.2, Liquid Waste Management Systems & Section 11.5 Process, Effluent and Airborne Radiation Monitoring Systems) is maintained by batch processing of all liquids, sampling before discharge and a controlled rate of release. Liquid effluents are monitored for radioactivity and rate of flow.

Additional details that define the licensing basis are described in FSAR Section 10.4.1, Main Condenser. The main condenser condenses and deaerates steam from the three low pressure turbine exhausts, the two main feedwater pump turbine exhausts, the turbine bypass control valves, and from various equipment vents and drains.

The main condenser is nonnuclear class.

Physical characteristics and performance requirements for the system are identified in FSAR Table 10.4-6, Condenser: Physical Characteristics And Performance Requirements.

The main condenser maintains normal turbine backpressure for all operating conditions.

The main condenser is designed to accept a 40 percent turbine bypass from the main steam system. The turbine bypass supports a 50 percent load rejection without a reactor trip, as discussed in FSAR Section 10.4.4, Turbine Bypass System.

FSAR Table 11.1-7, Secondary Side Steam Equilibrium Concentrations, lists the anticipated inventory of radioactive contaminants in the condenser.

The following measures are taken to prevent the loss of condenser vacuum.

- A Main Condenser Evacuation System is provided to establish and maintain condenser vacuum. A detailed description of this system design is provided in FSAR Section 10.4.2, Main Condenser Evacuation System (ARC).
- A vacuum priming system is provided on the condenser waterboxes (circulating water system) to ensure that the condenser tubes are full. A detailed description of this system design is provided in FSAR Section 10.4.5.3, Circulating Water and Associated Systems.
- Controls are provided to manually start a second 100 percent capacity air ejector, if necessary. A detailed description of this system design is provided in FSAR Section 10.4.2.2, Main Condenser Evacuation System.
- Loss of condenser vacuum has been anticipated and its consequences evaluated in the safety evaluation in FSAR Section 10.4.2.3, Main Condenser Evacuation System.
- Instrumentation required to monitor the status of the circulating water system are detailed in FSAR Section 10.4.5.5, Circulating Water and Associated Systems.

Regarding the ARC, additional details that define the licensing basis are described in FSAR Section 10.4.2. The ARC is designed to draw the initial vacuum in the condenser shells during startup, maintain vacuum during operation and dispose of noncondensible gases from the condenser.

The ARC is designed in accordance with GDC-60 and -64 with the provisions for controlling and monitoring the release of radioactivity to the environment.

As addressed in MPS3 Safety Evaluation Report (NUREG-1031, August 2, 1984), Section 10.4.1, "Main Condenser's Compliance with GDC-60", MPS3 has met the requirements of Section II of SRP Section 10.4.1 (GDC-60) and industry standards.

In addition to the evaluations described above, selected MPS3 systems were evaluated for the continued acceptability for the purpose of plant license renewal. The results of that review are found in NUREG-1838, Safety Evaluation Report Related to License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005. The main condenser is not within the scope of license renewal.

2.5.5.2.2 Technical Evaluation

2.5.5.2.2.1 Introduction

The main condenser is discussed in FSAR Section 10.4.1. The main condenser is a three-shell, single-pressure, deaerating type surface condenser with semi-cylindrical water boxes bolted at both ends. The condenser extracts the latent heat of vaporization from the low pressure turbine exhaust steam, the steam generator feedwater pump turbines exhaust steam, the turbine bypass system (when in operation) and miscellaneous flows, drains and vents during normal plant operation. This heat is transferred to the circulating water system. The resulting condensate is collected in the condenser hotwell before entering the condensate and feedwater system. The condensate hotwell level control system maintains sufficient level to provide the suction head for the condensate pumps. The condenser deaerates the condensate before it leaves the condenser hotwell.

The condenser utilizes circulating water for heat removal and transfer of the rejected heat to the Long Island Sound. The circulating water system is described in FSAR Section 10.4.5. The evaluation of the SPU effect on the circulating water system is described in Section 2.5.8.1, Circulating Water System.

The turbine bypass system is discussed in FSAR Section 10.4.4. The purpose of the turbine bypass system is to minimize the stresses on the nuclear steam supply system induced by changes in the secondary plant steam demand. At SPU conditions, the turbine bypass valves will bypass up to approximately 38 percent steam flow from the main steam headers directly to the main condenser. Refer to Section 2.5.5.3, Turbine Bypass for additional discussion of the turbine bypass system.

Balance of plant control system setpoints and instrumentation, related to condenser operation, are evaluated in this section and Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems.

2.5.5.2.2.2 Description of Analyses and Evaluations

The main condenser will experience higher steam flows due to the increase in LP turbine exhaust flow and steam generator feedwater pump turbines exhaust flow at the SPU power level and due to the SPU increase in the steam flow bypassed to the condenser by the turbine bypass system following a load rejection. The higher SPU turbine bypass steam flow during a load rejection transient is due to higher inlet pressures and flow rates to the turbine bypass valves. The evaluation determined the impact of the SPU conditions on condenser performance and integrity as follows:

- Determined the increased condenser duty and confirm the condenser's ability to reject heat to the circulating water system and maintain a low enough condenser backpressure for the turbine to meet its SPU performance requirements.
- Evaluated the condenser hotwell storage capacity to provide sufficient storage volume with the maximum condensate flow rate at SPU conditions.
- Evaluated the capability of the main condenser to remove dissolved gases and air in-leakage from the condensate.
- Evaluated the steam blowdown effects of increased steam flow at normal SPU power operation and during turbine bypass to the condenser following load rejection on condenser tube vibration.
- Evaluated the impact of the increased turbine bypass flow on condenser backpressure during turbine bypass conditions.
- Evaluated the impact of the increased steam flow on the condenser spargers, baffles, and impingement plates, provided to protect the condenser tube and internal components from damage due to incoming steam and water flows.
- Evaluated the impact of the increased steam flow on the plant design to control the release of radioactive effluents in accordance with GDC-60.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The main condenser is not within the scope of license renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries for the main condenser. Operating the main condenser at SPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.5.2.2.3 Results

The evaluation determined that the condenser satisfactorily removes the increased SPU heat loads, condenses the required steam flows, and maintains an acceptable vacuum using circulating water at the current operating flow rate.

The condenser hotwell capacity during the SPU conditions will continue to satisfy the minimum 5 minute condensate storage inventory requirement at maximum throttle flow as described in FSAR Section 10.4.

The ability of the condenser to remove air in-leakage remains acceptable at SPU conditions. Air in-leakage is not significantly affected by the uprate. It is generally due to leakage in the physical boundary of the condenser which is unchanged by SPU. The current capacity of the steam jet air ejectors is acceptable for SPU conditions. Refer to Section 2.5.3.2, Main Condenser Evacuation Systems for additional discussion.

The evaluation also confirmed that the condenser adequately withstands the steam blowdown effects of a 38 percent turbine bypass following a load rejection. A main condenser tube vibration evaluation determined that the existing support plate spacing is adequate for the SPU conditions. Therefore, no modifications are required for the existing condenser tube supports for SPU operation.

The increased steam flow rates at SPU conditions of normal operation and turbine bypass may increase the wear of condenser internal spargers (nozzles), baffles, and impingement plates. The SPU flow rates for condenser connections have been checked against design flow rates to verify acceptability at SPU. SPU flow rates are bound by design flows. Therefore, the condenser connections are acceptable for SPU.

The main condenser current turbine trip set point for low condenser vacuum at SPU conditions was evaluated and found to be acceptable.

The design of the main condenser does not change following the implementation of the SPU. Therefore, the SPU does not impact the ability of MPS3 regarding the control of radioactive material in accordance with GDC-60. The impact of SPU on radiological effluent releases from MPS3, radiation monitoring setpoints and compliance with 10 CFR 50, Appendix I, is discussed in Section 2.10.1, Occupational and Public Radiation Doses.

2.5.5.2.3 Conclusion

The DNC evaluation has adequately accounted for the effects of changes in plant conditions on the design of the main condenser and concludes that the main condenser will continue to maintain its ability to withstand the blowdown effects of the steam from the turbine bypass system and; thereby, continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-60 for preventing the consequences of failures in the system. Therefore, the proposed SPU is acceptable with respect to the main condenser.

2.5.5.3 Turbine Bypass

2.5.5.3.1 Regulatory Evaluation

The turbine bypass system is designed to discharge a stated percentage of rated main steam flow directly to the main condenser system, bypassing the turbine. This turbine bypass enables the plant to take step-load reductions up to the turbine bypass system capacity without the reactor or turbine tripping. The system is also used during startup and shutdown to control steam generator pressure. The DNC review focused on the effects of the proposed SPU on the load rejection capability, analysis of postulated system piping failures, and on the consequences of inadvertent turbine bypass system operation.

The NRC's acceptance criteria for the turbine bypass system are based on:

- GDC-4, insofar as it requires that structures, systems, and components important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures; and
- GDC-34, insofar as it requires that a residual heat removal system be provided to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded

Specific review criteria are contained in SRP section 10.4.4, Rev. 2 and guidance is provided in Matrix 5 of Section 2.1 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 10.4.4, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 Station design regarding conformance to:

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4)

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5, Tabulation of Codes and Classifications.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-34 is described in FSAR Section 3.1.2.34, Residual Heat Removal (Criterion 34)

  The residual heat removal system, in conjunction with the steam and power conversion system, is designed to transfer the fission product decay heat and other residual heat from the reactor core within acceptable limits. The transfer of the heat removal function from the steam and power conversion system to the residual heat removal system occurs when the reactor coolant system is at approximately 350°F and 375 psig.

  Suitable redundancy at temperatures above approximately 350°F is provided by the steam generators and associated piping systems.

  FSAR Chapter 10, Steam and Power Conversion System give details of the system design.

Additional details that define the licensing basis for the turbine bypass system are described in FSAR Sections 7.7.1.8, Steam Dump Control, and 10.4.4, Turbine Bypass System.

Technical Specification 3/4.3.2, Engineered Safety Features Actuation System Instrumentation, ensures the Low-Low T_{avg} trip instrumentation, which provides for the arming and disarming of the turbine bypass system, is operable.

The turbine bypass system, which is included in main steam system, was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, date published October 2005, documents the result of the review. NUREG-1838 Sections 2.3B.4.1 and 3.4B are applicable to the turbine bypass system.

2.5.5.3.2 Technical Evaluation

2.5.5.3.2.1 Introduction

The turbine bypass system discharges a portion of the main steam flow directly to the main condenser bypassing the turbine. The system is designed to remove reactor coolant system sensible heat for a large rapid load reduction or reactor trip, and during plant start-up and shutdown to control steam generator pressure. With turbine bypass unavailable, a large rapid turbine load reduction could result in the undesirable lifting of the pressurizer and main steam safety valves.

The existing turbine bypass system is designed to pass 40 percent of the main steam flow at the current reactor thermal power to the condenser. In conjunction with the rod control system, which accommodates 10 percent of the load reduction, the turbine bypass system permits the NSSS to withstand a large load rejection equivalent to 50 percent reactor thermal power at a maximum turbine unloading rate of 200 percent per minute or a turbine trip at less than 50 percent reactor thermal power without lifting the pressurizer or main steam safety valves.

2.5.5.3.2.2 Description of Analyses and Evaluations

The following attributes of the turbine bypass system were evaluated to ensure they are capable of performing their intended functions at SPU conditions:

- System design pressure and temperature
- Steam hammer
- Piping flow velocities
- Operability of turbine bypass system

Additionally, other evaluations and interface functions of turbine bypass system and components are addressed in the following sections:

- Section 2.2.2.2, Balance of Plant Piping and Supports (Non-Class 1), with respect to postulated system piping failures (steam hammer loads)
- Section 2.5.5.1, Main Steam, with respect to providing a flow path for the turbine bypass system
- Section 2.5.5.2, Main Condenser, with respect to providing heat sink and the condenser's ability to withstand the blowdown effects of the steam from the turbine bypass system
- Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems, with respect to turbine bypass system set points
- Section 2.4.2, Plant Operability, with respect to turbine bypass system's ability of the turbine bypass system to support a step load reduction of up to 50 percent
- Section 2.8.5.1, Increase in Heat Removal by the Secondary System, with respect to turbine bypass system valve opening

Impact on Renewed Plant Operating License and License Renewal Programs

DNC has evaluated the SPU impact on the conclusion reached in the MPS3 license renewal safety evaluation report for the main steam system which includes the turbine bypass system. As stated in Section 2.5.5.3.1, portions of the turbine bypass system are within the scope of License Renewal. SPU activities are not adding any new components within the existing license renewal scoping evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the turbine bypass system at SPU conditions do not add any new or previously unevaluated materials to the system. System components internal and external environments remain within the parameters previously evaluated.

2.5.5.3.2.3 Results

System Design Pressure/Temperature

The turbine bypass system is connected to the main steam manifold upstream of turbine stop valves and is considered part of the main steam system. The SPU heat balance operating pressure and temperature (maximum 957 psig and 541ºF) at main steam manifold are bounded by the current system design pressure and temperature (1185 psig and 600°F) for the turbine bypass system from main steam manifold up to and including the turbine bypass valves.

The SPU operating pressures and temperatures are bounded by the current system design pressure and temperature for the turbine bypass system from the turbine bypass valves to the main condenser (250 psig and 600°F).

Steam Hammer

The capability of the turbine bypass system to withstand adverse dynamic loads (e.g., steam hammer resulting from turbine control valve fast closure or turbine stop valve closure for turbine protection) at SPU conditions is addressed in Section 2.2.2.2, Balance of Plant Piping and Supports (Non-Class 1).

Piping Flow Velocities

The current piping design velocity of less than 250 ft/sec is greater that the industry standard guidelines for continuously operated steam piping (100 to 167 ft/sec). This was selected based on the infrequent use of the turbine bypass system, less than 2 percent of the time. Flow velocities in the turbine bypass system from the main steam manifold to the turbine bypass valves (231 ft/sec, 206 ft/sec and 195 ft/sec for 24 inch, 18 inch and 10 inch lines respectively) are bounded by the current design velocity criterion (250 ft/sec) with the exception of 26 inch line (264 ft/sec). For this 26 inch line the velocity exceeds the original design velocity by 6 percent which is negligible.

Operability of Turbine Bypass System

Turbine trip without reactor trip analysis showed that with the current load rejection controller set points the pressurizer power operated relief valves (PORVs) could be challenged at SPU conditions. Consequently, the load rejection controller set points will be modified to maintain peak pressurizer pressure below the PORV set point. Refer to Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems for additional details.

The results of the 50 percent load rejection transient analysis with the revised turbine bypass set points demonstrated that no reactor trip or emergency safety features were challenged. The minimum margins to overtemperature ΔT and overpower ΔT trip setpoints available were approximately 10.2 percent nominal ΔT and 8.1 percent nominal ΔT respectively. The pressurizer PORVs were not challenged for the transient and the main steam system pressure remained less than the main steam safety valves set point of 1185 psig during the transient. The control systems response was smooth during the transient with no excessive oscillatory responses. Refer to Section 2.4.2, Plant Operability for additional details.

Refer to Section 2.8.5.1, Increase in Heat Removal by the Secondary System, for the evaluation of inadvertent turbine bypass system actuation.

Refer to Section 2.5.5.2, Main Condenser, for the evaluation of the impact on the main condenser due to turbine bypass operation.

Based on these analyses and evaluations, the turbine bypass system is acceptable at SPU conditions.

2.5.5.3.3 Conclusion

DNC has reviewed the evaluation of the effects of the proposed SPU on the turbine bypass system. DNC concludes that the evaluation has adequately accounted for the effects of changes in plant conditions on the design of the system. DNC concludes that the turbine bypass system will continue to provide a means for shutting down the plant during normal operations and turbine bypass failures will not adversely affect essential systems or components. Based on this, DNC concludes that the turbine bypass system will continue to meet the current MPS3 licensing basis with respect to the requirements of GDC-4 and GDC-34. Therefore, DNC finds the proposed SPU is acceptable with respect to the turbine bypass system.

2.5.5.4 Condensate and Feedwater

2.5.5.4.1 Regulatory Evaluation

The condensate and feedwater system (CFS) provides feedwater at the appropriate temperature, pressure, and flow rate to the steam generators. The only part of the condensate and feedwater system classified as safety-related is the feedwater piping from the steam generators up to and including the outermost containment isolation valve. The DNC review focused on the effects of the proposed SPU on previous analyses and considerations with respect to the capability of the CFS to supply adequate feedwater during plant operation and shutdown, and to isolate components, subsystems, and piping in order to preserve the system's safety function. The DNC review also considered the effects of the proposed SPU on the feedwater system, including the auxiliary feedwater system piping entering the steam generator, with regard to possible fluid flow instabilities (e.g., water hammer) during normal plant operation, as well as during upset or accident conditions.

The acceptance criteria for the review are:

- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects.
- GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions
- GDC-44, insofar as it requires that a system with the capability to transfer heat loads from safety-related structures, systems, and components to a heat sink under both normal operating and accident conditions be provided, and that suitable isolation be provided to ensure that the system safety function can be accomplished, assuming a single failure

Specific review criteria are contained in SRP Section 10.4.7 and guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 10.4.7, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to conformance to:

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4)

SSCs important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

SSCs important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5, Tabulation of Codes and Classifications.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-5 is described in FSAR Section 3.1.2.5, Sharing of Structures, Systems, and Components (Criterion 5)

Other facilities and systems not important to safety within the definitions of GDC-5, but which are shared by the units are:

Warehousing facility houses the Millstone 2 condensate polishing system, the Millstone 2 and 3 (removed from service) condensate demineralizer radioactive liquid waste systems. The Unit 2 condensate polishing solid waste system is designed to process radioactive waste from Millstone 2 and 3.

- GDC-44 is described in FSAR Section 3.1.2.44, Cooling Water (Criterion 44)

The reactor plant component cooling water system, the charging pump cooling system, spent fuel pool cooling and purification system, and the safety injection pump cooling system, transfer heat from systems containing reactor coolant to the service water system. Together, these systems transfer heat to the ultimate heat sink from structures, systems, and components important to safety during normal and accident conditions.

These systems are designed with suitable redundancy in components, with leak protection, and with the capability to isolate redundant components. The systems are designed to satisfy the cooling water requirements assuming a single failure and either a loss of onsite or offsite power.

Note that the CFS is not specifically addressed; however, the feedwater system does have safety functions, which are considered as part of this GDC, by providing redundant flow paths for the auxiliary feedwater system flow to the steam generators for heat removal from the reactor coolant system and by providing the required safety related, redundant isolation functions of main feedwater during postulated steamline breaks.

Additional details that define the licensing basis for the condensate and feedwater system are described in the following FSAR Sections:

- Section 10.4.7, Condensate and Feedwater Systems
- Section 6.2.1.4, Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures Inside Containment
- Section 6.2.4, Containment Isolation System
- Chapter 15, Accident Analyses
- Section 3.9N, Mechanical Systems and Components
- Section 3.7B.3, Seismic Subsystem Analysis
- Technical Specification 3/4.6.3, Containment Isolation Valves, ensures the operability of the feedwater isolation valves.

The CFS was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Unit 2 and 3, dated August 1, 2005 documents the results of that review. NUREG-1838 Sections 2.3B.4.2, 2.3B.4.3, and 3.4B are applicable to the condensate and feedwater system.

2.5.5.4.2 Technical Evaluation

2.5.5.4.2.1 Introduction

The CFS functions to collect steam condensed from the low pressure turbines' exhaust, the two main feedwater pump turbine exhausts, the turbine bypass control valves, and from various equipment vents and drains in the main condenser and heat this condensate. It is then sent back to the steam generators at the temperature and pressure required for heat removal from the reactor coolant system as well as power generation at SPU conditions.

Specific condensate and feedwater system design functions include:

Condensate System:

- Condense steam from the low pressure turbine exhausts, the feedwater pump turbine exhausts, and the turbine bypasses
- Heat the condensate to the temperature required by the feedwater system to meet the NSSS vendor temperature requirements at the steam generator inlet
- Return feedwater heater drains and moisture separator drains to the feedwater system
- Maintain the NPSH required by the feedwater pumps during steady state and transient conditions
- Route condensate through the condensate demineralizer mixed bed
- Provide condensate recirculation back to the condenser

- Provide water for condensate and feedwater pump mechanical seals, turbine exhaust hood sprays, turbine bypass desuperheating sprays, and various miscellaneous services
- Maintain condenser hotwell level during steady state and transient operating conditions
- Provide non-safety grade backup source for the auxiliary feedwater system

Feedwater System:

- Transfer water from the condensate system to the steam generators
- Heat feedwater to meet temperature requirements at the steam generator inlet
- Raise feedwater pressure from condensate system pressure to that required to feed the steam generators
- Automatically control the water level in the steam generators during steady state and transient conditions in conjunction with the steam generator water level control system
- Meet containment isolation requirements
- Provide isolation of feedwater in event of high energy pipe breaks

The condensate system includes three nominal 50 percent capacity condensate pumps. The feedwater system includes two nominal 50 percent capacity steam turbine driven pumps which normally operate and one nominal 50 percent capacity electric motor driven pump which serves as a backup. The heater drain system includes three nominal 33 percent capacity heater drain pumps. The moisture separator drain system includes two nominal 50 percent capacity moisture separator drain pumps.

Condensate drains from the condenser hotwell to the condensate pumps, which supply water to the suction of the feedwater pumps, which provides feedwater to the steam generators. The heater drain pumps take suction from the drain cooler portion of the fourth point feedwater heaters (which collect the cascaded drains from first, second, and third point feedwater heaters) and discharge to the condensate system upstream of the third point feedwater heaters. The moisture separator drain pumps take suction from the moisture separator drain tanks and deliver the water to the condensate system at the suction header of the main feedwater pumps.

The condensate polishing demineralizers are aligned to full condensate flow during normal plant power generation. Five stages of low pressure feedwater heating and one stage of high pressure feedwater heating are provided; arranged in three separate, parallel trains. The condensate system also provides cooling water to the air ejector condensers and steam packing exhauster condenser.

2.5.5.4.2.2 Description of Analyses and Evaluations

The condensate and feedwater systems and components were evaluated to determine their capability to perform their intended functions at SPU conditions. The evaluation considered the effects of the proposed SPU on the following system/component design aspects:

- Design pressures/temperatures of piping and components versus SPU operating pressures/temperatures

- Flow velocities
- Pump and pump supporting subsystems design capabilities, including NPSH, flow, head, brake horsepower, minimum flow protection and seal water supplies, and process setpoints for protective functions, such as feedwater pump suction pressure
- Capacity and control capability of the feedwater flow control valves
- Feedwater isolation valve closure within the required time period at SPU hydraulic conditions of flow and pressure drop
- Feedwater heaters design parameters and operating characteristics listed below.
  - Thermal performance
  - Shell side and tube side velocities, including steam dome velocity
  - Shell and tube side pressure drops
  - Shell and tube side relief valve capacities & setpoints
  - Shell side venting capacity
  - Flow induced vibration
  - Shell side and tube side design pressure/temperature

The condensate and feedwater systems were evaluated by utilizing a hydraulic model of the system components and piping and the SPU heat balances. Physical plant data for the installed components and piping were utilized in the hydraulic model.

Current plant operating data were gathered and included in the current operating heat balances to reflect the present day performance of the existing components. The current operating heat balances were then evaluated at the SPU operating conditions and issued as SPU heat balances. The SPU heat balances were used to establish the flow, temperatures and heat transfer requirements at the SPU power level.

A review of available industry operating experience related to the condensate and feedwater system was also performed.

Other evaluations of condensate and feedwater systems and components are addressed in the following sections:

- Section 2.1.8, Flow-Accelerated Corrosion, which evaluates the effects of increased flow and velocity for erosion/corrosion concerns
- Section 2.2.2.2, Balance of Plant Piping and Supports (Non-Class 1), which evaluates piping/component supports and water hammer effects
- Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects, which evaluates protection against dynamic effects, including GDC-4 requirements, of missiles, pipe whip and discharging fluids
- Section 2.2.4, Safety-Related Valves and Pumps, which evaluates feedwater isolation valve testing and closure requirements

- Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems, which evaluates condensate and feedwater instrumentation

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 License Renewal Safety Evaluation Report for the CFS. As stated in Section 2.5.5.4.1, portions of the CFS are within the scope of License Renewal. SPU activities include modifications to the feedwater pump speed control system and feedwater pump turbines to meet the SPU conditions. These changes do not introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operating the condensate and feedwater systems at SPU conditions does not add any new types of materials or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.5.4.2.3 Results

The following subsections describe the specific condensate and feedwater system design and performance capabilities while operating at SPU conditions.

System Operating Parameters – Current versus SPU Parameters

The condensate and feedwater system operating parameters; flow, temperature and pressure, were determined from hydraulic modeling of the piping systems and from the current operating and SPU heat balances. Table 2.5.5.4-1 compares the current condensate and feedwater system parameters to the predicted SPU parameters.

Design Pressures/Temperatures – Components and Piping

The current design pressures and temperatures of condensate and feedwater components and piping bound the SPU operating parameters shown in Table 2.5.5.4-1.

The design pressure of the condensate system is 700 psig. The design temperature of the condensate system to the inlet of the sixth point heaters is 200°F and 390°F from and including the sixth point heaters to the feedwater pump suction nozzle.

The design pressure of the feedwater system from the feedwater pump discharge up to and including the feedwater isolation valves is 1800 psig and 1185 psig from the feedwater isolation valves to the steam generator inlet nozzle. The design temperature of the feedwater system from the feedwater pumps to the inlet of the first point heaters is 400°F and 470°F from and including the first point heaters to the steam generator inlet nozzle.

Flow Velocities – Piping

Flow velocities through the condensate and feedwater system were evaluated at SPU conditions. Velocities remain below the industry design guidelines for all system piping with the exception of the motor driven feedwater pump suction and discharge piping, which are not normally used at full power operation, and the inlet reducer/outlet expander of a control valve in the main condensate header. These individual pipes are currently evaluated as part of the flow accelerated corrosion program and will continue to be monitored after SPU as described in Section 2.1.8, Flow-Accelerated Corrosion.

Potential vibration issues resulting from increased flow velocities at SPU are evaluated in Section 2.12, Power Ascension and Testing Plan. The system instrumentation has also been evaluated for flow induced vibration effects. MPS3 condensate and feedwater system uses Leading Edge Flow Meters and flow venturis that do not contain probes extending into the flow stream. Thermowells do extend into the flow stream and are used throughout the condensate and feedwater system for temperature measurement. The SPU velocities are bounded by the maximum velocities which thermowells are designed.

Condensate and Feedwater Pumps and Supporting Subsystems

The condensate pumps, feedwater pumps, and their supporting subsystems will continue to perform their intended functions following implementation of the SPU based on the evaluations and modifications described below:

The existing condensate pumps operate within acceptable limits at SPU with sufficient NPSH, flow and head. The condensate pump motors continue to provide sufficient motive force for pump operation and the brake horsepower is below nameplate rating at SPU conditions.

The existing condensate pump recirculation system allows sufficient flow for condensate pump protection and supplies the minimum flow required by the steam packing exhauster condenser and steam jet air ejectors.

SPU evaluations demonstrate the steam generator feedwater pump turbines are capable of providing motive power and required speed to the steam generator feedwater pumps to provide the required feedwater flow and pressure to steam generators at SPU conditions with modifications. To preclude any problems with design capability and performance at SPU conditions, the entire turbine steam path including the rotating assembly and the diaphragms will be replaced.

The SPU evaluations determined that increasing the feedwater pump turbine speed to 5125 rpm provides the required flow, head, and NPSH and maintains the feedwater flow control valves in their pre-SPU position. The setpoint which controls feedwater turbine speed based upon differential pressure between the main steam and feedwater headers will be increased accordingly.

The feedwater pump low suction pressure alarm and trip setpoints do not change and will continue to provide protection for the feedwater pump at SPU.

The existing feedwater pump recirculation subsystem allows sufficient flow to satisfy the pump minimum flow requirements for implementation of the SPU.

The feedwater pump seal water booster pumps continue to provide sufficient flow and pressure to the feedwater pumps from the condensate system.

Feedwater Flow Control Valves

The existing feedwater flow control valves are sufficient to provide the required flow at the required pressure drop at SPU conditions. The valves will continue to operate at approximately

84 percent open during normal plant operation following SPU implementation and provide sufficient control over a range of operating conditions due to the increase in feedwater pump turbine speed to 5125 rpm and setpoint increase for feedwater to main steam header differential pressure.

The sizing and control capability of the feedwater flow control valves, together with the hydraulic operation of the condensate and feedwater pumps, provides sufficient flexibility to accommodate plant load rejection transients by providing 91 percent of rated flow with a 100 psi increase in steam generator pressure.

Feedwater Isolation Valves

Feedwater isolation is required for a variety of postulated transients and accident events. The current plant design provides for feedwater isolation using the feedwater isolation trip valves, with the feedwater flow control and associated bypass valves providing backup.

The feedwater isolation trip valves along with the feedwater flow control and their associated bypass valves, have been evaluated for the increased flow rates, differential pressures, and temperatures at SPU. These valves will continue to meet the existing required closure times for SPU conditions.

Containment isolation is accomplished by the provision of check valves on the feedwater headers and branch lines inside containment. The containment isolation requirements are unaffected by SPU and the current plant design features remain acceptable.

Feedwater Heaters

The feedwater heaters were evaluated for SPU operation based on their current design, materials, construction, and performance. Current plant operating and inspection data and the predicted SPU heat balance conditions have been reviewed to perform the evaluation. The industry criteria established by the HEI have been generally used as the guidelines for acceptance.

The feedwater heaters meet the thermal performance requirements of the SPU conditions. SPU heat balances show that the expected SPU power generation will be achieved. Thereby confirming that the existing feedwater heaters will perform their intended function during SPU operation.

The velocities of some feedwater heater tubes, nozzles and internal sections are above the HEI guidelines, manufacturer's guidelines or both, at SPU conditions. No physical changes are considered necessary. However, the long-term effects of the higher velocity in the tubes, nozzles and shells will be monitored as described in Section 2.1.8, Flow-Accelerated Corrosion. All steam dome velocities were found to be acceptable for SPU.

The feedwater heater tube side pressure drops are acceptable for SPU with all but two heaters below 20 psid and the highest at 20.9 psid. The recommended threshold for considering replacement is 30 psid. Shell side pressure drops are within HEI standards.

The feedwater heaters shell and tube side relief valves were evaluated. The existing relief valve capacities and setpoints are acceptable for SPU operation.

The feedwater heaters shell side vents are acceptable for SPU operation.

The feedwater heaters were also evaluated for flow induced vibration. The results of these evaluations demonstrated there will not be any flow induced vibration at SPU conditions.

The feedwater heaters shell and tube side design pressures and temperatures bound the operating pressures and temperatures and are acceptable at SPU conditions.

In summary, the design and construction of the feedwater heaters is acceptable for continued operation at SPU conditions with the existing monitoring programs in place to evaluate the potential for long term degradation. The Flow Accelerated Corrosion evaluation is described in Section 2.1.8, Flow-Accelerated Corrosion.

Industry Operating Experience

The Industry Operating Experience pertaining to the condensate system relates to the following areas:

1. Condensate Pump performance limitations.
2. Setpoint margins and control system anomalies.
3. Condensate Demineralizer differential pressures.

The existing condensate pumps have been evaluated and will operate at SPU within acceptable limits with sufficient NPSH, flow and head. Condensate system instrumentation has been evaluated in Section 2.4, Instrumentation and Controls, and found to be acceptable for SPU. Condensate Demineralizers have been evaluated for the increased flow rates and differential pressures at SPU and will continue to perform their intended function.

The Industry Operating Experience pertaining to the feedwater heaters relates to the following areas:

1. Feedwater Heater Shell Design Pressures and Temperatures.
2. Drain Paths and Capabilities.
3. Baffles and Tubes Limitations and Leaks.

The above discussion states the feedwater heaters shell and tube side design pressures and temperatures have been evaluated and bound the SPU operating pressures and temperatures. The drain paths and capabilities have been evaluated and determined that some of the nozzles are undersized resulting in higher velocities. The long-term effects of the higher velocities will be monitored as discussed in Section 2.1.8, Flow-Accelerated Corrosion. The feedwater heater drain valves have been evaluated and found to be acceptable for SPU.

The Industry Operating Experience pertaining to the feedwater system relates to the following areas:

1. Control Systems

2. Control Valve Limitations.

3. Pump performance limitations and modification issues.

Regarding control systems, the feedwater to main steam header differential pressure setpoint increase will be performed in accordance with plant design change procedures. The existing feedwater flow control valves will provide sufficient flow and will remain in their current position at SPU. Increasing the feedwater pump turbine speed to 5125 rpm provides the required flow, head, and NPSH. The feedwater pump turbine rotating assembly and the diaphragms will be replaced in accordance with plant design change procedures.

2.5.5.4.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the CFS. DNC concludes that the evaluation has adequately accounted for the effects of changes in plant conditions on the design of the CFS under the proposed SPU. The CFS, with the implementation of the modifications, monitoring and inspections described above, will continue to maintain its ability to satisfy feedwater requirements for normal operation and shutdown, withstand water hammer, maintain isolation capability in order to preserve the system safety function, and not cause failure of safety-related structures, systems, and components. The feedwater heaters will not experience flow induced vibration. The CFS will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-4, GDC-5, and GDC-44. Therefore DNC finds the proposed SPU acceptable with respect to the CFS.

Table 2.5.5.4-1
Condensate and Feedwater System Operating Parameters

	Current Operating Parameters	Predicted SPU Operating Parameters
Condensate System		
Flow Rate, lbm/hr	9,300,000	10,057,000
Condenser Pressure, inches HgA @ Circ. Water Temperature, °F	1.99 @ 55.5°F CW	1.55 @ 33°F CW
Condensate Pump Discharge Pressure, psia	557	549
Condensate Supply Temperature, °F (FWS Pump Suction)	361	367
Heater Drain System		
Heater Drain Pump Flow, lbm/hr	4,195,000	4,588,000
Separator Drain System		
Separator Drain Pump Flow, lbm/hr	1,517,000	1,622,000
Feedwater System		
Flow Rate, lbm/hr	15,012,000	16,267,000
Turbine Driven Feedwater Pump Speed, rpm	4900/5000	5125
Feedwater Pump Discharge Pressure, psia	1,144	1,171
Steam Generator Supply Pressure, psia	1,019	1,020
Steam Generator Supply Temperature, °F	436	443
Steam Generator Feedwater Supply Velocity, ft/s	19.3	20.5

2.5.6 Waste Management Systems

2.5.6.1 Gaseous Waste Management Systems

2.5.6.1.1 Regulatory Evaluation

The Gaseous Waste Management System (GWS) consists of three subsystems: the degasification subsystem, the process gas (hydrogenated) subsystem, and low activity process vent (aerated) subsystem. In the degasification subsystem, the fluid from the reactor coolant letdown stream (CHS), or alternately, from the reactor plant gaseous drains system (DGS), is sent to a degasifier, where noncondensible gases are removed. The remaining liquid may be transferred to the volume control tank (CHS) or to the boron recovery system (BRS). The normal flowpath is from the reactor coolant letdown to the volume control tank. The gases are forwarded to the process gas portion of GWS.

In the process gas (hydrogenated) subsystem, the noncondensible gas stream is first dehydrated. Then, radioactive iodine is removed and the activity of the radioactive xenon and krypton is reduced by absdorption on charcoal beds. Finally, the decayed gas is released into the process vent portion of GWS.

In the low activity process vent (aerated) subsystem, aerated and hydrogenated gas streams from various plant inputs (including the process gas portion of GWS) are collected, dehydrated, and discharged to the reactor plant ventilation system (HVR) for release to the environment via the Millstone stack. The gas streams are monitored for radioactivity prior to release.

DNC review focused on the effects that the proposed SPU may have on 1) the design criteria of the gaseous waste management systems, 2) methods of treatment, 3) expected releases, (4) principal parameters used in calculating the releases of radioactive materials in gaseous effluents, and (5) design features for precluding the possibility of an explosion if the potential for explosive mixtures exist.

The acceptance criteria for the review are:

- 10 CFR 20.1302 insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values
- GDC-3 insofar as it requires that:
  - Safety-related structures, systems, and components be designed and located to minimize the probability and effect of fires
  - Noncombustible and heat-resistant materials be used
  - Fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on safety-related structures, systems, and components
- GDC-60 insofar as it requires that the plant design include means to control the release of radioactive effluents

- GDC-61 insofar as it requires that systems that contain radioactivity be designed with appropriate confinement
- 10 CFR 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for design objectives and limiting conditions for operation to meet the “as-low-as-is-reasonably achievable” criterion

Specific review criteria are contained in SRP Section 11.3 and guidance is provided in Matrix 5 of RS-001.

Millstone 3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Sections 11.3, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the GDC is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 Station design relative to conformance to:

- GDC-3 is described in the FSAR Section 3.1.2.3, Fire Protection (Criterion 3)

  The design of Millstone 3 minimizes the probability and effect of fires and explosions on structures, systems, and components important to safety. Noncombustible and heat-resistant materials are used wherever practical throughout the unit. Fire detection and fire suppression systems of sufficient capacity and capability minimize the adverse effects of fires on structures, systems, and components important to safety. Fire suppression systems are designed to assure that rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

- GDC-60 is described in the FSAR Section 3.1.2.60, Control of Releases of radioactive Materials to the Environment (Criterion 60)

  In all cases, the design for radioactivity control is based on:

  1. The requirements of 10 CFR 20, 10 CFR 50, and 10 CFR 50, Appendix I, for normal operations and for transient situation that might reasonably be anticipated to occur.

  2. 10 CFR 50.67 dose level guidelines for potential accidents of extremely low probability of occurrence.

  All release paths, including ventilation and process streams, are monitored and controlled as described in FSAR Section 11.5.

  The activity level of the radioactive gaseous waste effluents subsequent to release through the 375-foot Millstone stack are monitored (FSAR Section 11.3.2.4). Under conditions of concurrent fuel failure and steam generator tube leakage, some radioactive gas would be present and suitably controlled in the steam jet air ejector discharge in the condenser air removal system (FSAR Section 10.4.2) and in the flow from the steam packing exhauster fan in the turbine generator gland seal and exhaust system (FSAR Section 10.4.3). The steam jet air ejector discharge is directed to the Millstone stack while the seal steam packing exhauster fan discharges through the condensate polishing enclosure roof.

- GDC-61 is described in the FSAR Section 3.1.2.61, Fuel Storage and Fuel Handling and Radioactive Control (Criterion 61)

  Safety related components in the gaseous waste management system (FSAR Section 11.3) are designed to allow periodic inspection and testing to ensure proper operation. Performance of components important to safety in the radioactive gaseous waste system is verified by extensive process fluid analysis and continuous radiation monitoring of gaseous effluents.

  The gaseous waste management system areas are designed to meet the requirements of 10 CFR 20 in providing radiation shielding for operating personnel based on anticipated radiation dose rates and occupancy. Periodic surveys by health physics personnel and continuously operated radiation monitors located in areas selected to afford maximum personnel protection (FSAR Section 12.1) ensure that radiation design levels are not exceeded during lifetime of the unit.

  Radiation gases and particulates released from components are collected by the reactor plant aerated vents system. Uncontrolled leakage of radioactive gases and particulates which may leak from spent fuel, radioactive waste, or components containing radioactive fluids is collected and treated by the respective building ventilation filtration system (FSAR Section 9.4) or supplementary leakage collection and release system (FSAR Section 6.5.1). All discharges from these systems are monitored for radioactivity.

As stated in FSAR Section 1.2.6:

Radioactive wastes are collected, processed, and disposed of in a safe manner complying with appropriate regulations, in particular, NRC regulations 10 CFR 20, 10 CFR 50, Appendix I, 10 CFR 61, 10 CFR 71, 49 CFR 171-178, 10 CFR 100, and General Design Criteria 60 and 64 (FSAR Sections 3.1.2.60 and 3.1.2.64). There are three interrelated radioactive waste treatment systems: radioactive liquid waste, radioactive gaseous waste, and radioactive solid waste. FSAR Chapter 11 describes these systems.

Additional details that define the licensing basis for the gaseous waste system are described in FSAR Section 11.3, Gaseous Waste Management Systems. The gaseous waste management system processes and controls the release of radioactive gaseous effluents to the site environs so as to maintain the exposure to radioactive gaseous effluents of persons in unrestricted areas to as low as reasonably achievable (10 CFR 50, Appendix I, May 5, 1975). This is accomplished while also maintaining occupational exposure as low as reasonably achievable and without limiting plant operation or availability. The concentrations of radioactive materials in gaseous effluents released to an unrestricted area do not exceed the limits in 10 CFR 20, Appendix B, Table 2, Column 1. The radioactive gaseous waste system meets General Design Criteria 60 and 64 of 10 CFR 50, Appendix A. The design of the system precludes an explosive mixture from accumulating. Since the system operates above atmospheric pressure, inleakage can not occur. Instrumentation with automatic alarm functions monitors the concentrations of hydrogen and oxygen in portions of the system having the potential for containing explosive mixtures.

FSAR Chapter 15, Accident Analysis addresses a radioactive gaseous waste system failure (FSAR Section 15.7.1). The analysis concludes that the event will not cause a Condition IV event and the radiological consequences are within the guidelines of 10 CFR 100.

As addressed in MPS3 Safety Evaluation Report (NUREG-1031, August 2, 1984), Section 11.3, “Gaseous Waste Management System”, MPS3 gaseous waste management system design is acceptable and meets the requirements of 10 CFR 20.106; 10 CFR 50.34a; GDCs -3, -60, -61, and -64; and 10 CFR 50, Appendix I, as referenced in the SRP.

The MPS3 Gaseous Waste Management System was evaluated for continued acceptability to support plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005 documents the results of that review. NUREG-1838, Section 2.3B.3.48 is applicable to the Gaseous Waste Management System.

2.5.6.1.2 Technical Evaluation

2.5.6.1.2.1 Introduction

The gaseous waste management system is described in FSAR Section 11.3 and has the capability to control, collect, process, hold, and dispose of gaseous radioactive wastes generated from normal operation and anticipated operational occurrences.

The gaseous waste management system includes the gaseous waste system and ventilation systems. The gaseous waste system consists of three subsystems: the degasification subsystem, the process gas (hydrogenated subsystem), and the low activity process vent (aerated) subsystem.

2.5.6.1.2.2 Description of Analyses and Evaluations

The gaseous waste management system and components were evaluated to ensure they are capable of performing their intended functions at SPU conditions. The evaluation compared the existing design parameters of the systems/components with the SPU conditions.

2.5.6.1.2.3 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

In addition to the evaluations described above, the gaseous waste system was evaluated for the continued acceptability for the purpose of plant license renewal. The results of that review are found in NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005. System and system component materials of construction, operating history and programs used to manage aging effects are documented in the SER. The gaseous waste system was determined to be within the scope of the license renewal and components subject to age management review are evaluated on a plant wide basis as commodities, where the generic commodity groups are described in SER Section Number 2.3B.3.48.

2.5.6.1.2.4 Results

The implementation of power uprate does increase the inventory of gas normally processed by the gaseous waste management system, but the plant system functions are not changing and the assumptions related to volume inputs remain the same. The SPU does not add or change any of the sources of potentially explosive mixtures.

Potentially radioactive gas is collected from selected systems and components and is directed to the gaseous waste management system. The implementation of SPU does not add any new sources of potentially contaminated gases, nor does it create any new flow paths or routes that would allow the contamination of uncontaminated gases.

The SPU results in an increase in the equilibrium radioactivity in the reactor coolant. This change in radioactivity of the reactor coolant impacts the concentrations of radioactive nuclides in the waste disposal systems. The radiological impact of the increased activity in the waste disposal systems is detailed in Section 2.10.1, Occupational and Public Radiation Doses.

The evaluation of the gaseous waste management system at SPU conditions shows concurrence with 10 CFR 20.1302, insofar as the annual average concentrations of radioactive materials released at the boundary of the unrestricted area will not exceed specified values. This will be demonstrated by the continued compliance post SPU to the annual dose objective of 10 CFR 50, Appendix I, as discussed in Section 2.10.1, Occupational and Public Radiation Doses. Discharge streams will remain appropriately monitored and adequate safety features remain incorporated to preclude excessive releases, in accordance with the offsite dose calculation manual.

The evaluation of the gaseous waste management system at SPU conditions demonstrates that the MPS3 will continue to meet the current licensing basis with respect to the requirements of GDC-3, insofar as it requires that the plant design includes fire detection and fighting systems of appropriate capacity and capability for the protection of structures, systems and components important to safety. There is no impact to the fire detection and fighting systems due to SPU. See Section 2.5.1.4, Fire Protection. There are no new gaseous waste components added as a result of the SPU and the gaseous waste flow rates, gaseous inventory and process conditions are not changed by the SPU. Thus the existing systems retain their compliance to GDC-3.

The evaluation of the gaseous waste management system at SPU conditions demonstrates that the MPS3 will continue to meet the current licensing basis with respect to the requirements of GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. This design capability remains unchanged by the SPU. The handling, control, and release of radioactive materials are in compliance with 10 CFR 50, Appendix I, and is described in the offsite dose calculation manual.

The evaluation of the gaseous waste management system at SPU conditions demonstrates that the MPS3 will continue to meet the current licensing basis with respect to the requirements of GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement to ensure adequate safety under normal and postulated accident conditions. This design capability remains unchanged by the SPU.

The evaluation of the gaseous waste management system at SPU conditions demonstrates conformance with the requirements of 10 CFR 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for dose design objectives and limiting conditions for operation to meet the “as-low-as-is-reasonably-achievable” criterion has been formalized in the technical specifications requirements for the radioactive effluent controls program and the offsite dose calculation manual. Refer to Section 2.10.1, Occupational and Public Radiation Doses for details.

As discussed above, the gaseous waste management system is within the scope of license renewal. However, the gaseous waste management system flow rates, gaseous inventory and process conditions are not changed by the SPU and are within the original design parameters of the system. The increased concentration of radionuclides within the system does not effect the overall aging of systems/components and there are no system/component modifications necessary. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the gaseous waste management systems at SPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. A review of internal and industry operating experience has not identified the need to modify the basis for Aging Management Programs to account for the effects of SPU. Thus, no new aging effects requiring management are identified.

2.5.6.1.3 Conclusion

The evaluation has confirmed that there is no change in the limiting amount of gaseous waste processed by the Gaseous Waste System after SPU and that the increase in fission products resulting from the increased equilibrium radioactivity of the reactor coolant system does not affect the ability of the gaseous waste management system to process and control releases of radioactive materials and preclude the possibility of an explosion if the potential for explosive mixtures exists. The gaseous waste management system will continue to meet its design functions and the requirements of 10 CFR 20.1302 and 10 CFR 50, Appendix I, Sections II.B II.C, IID. MPS3 will continue to meet the current licensing basis with respect to the requirements of GDC-3, -60 and -61. Therefore, the proposed SPU is acceptable with respect to the gaseous waste management system.

2.5.6.2 Liquid Waste Management Systems

2.5.6.2.1 Regulatory Evaluation

The DNC review of the liquid waste management systems focused on the effects that the proposed SPU may have on previous analyses and considerations related to the liquid waste management systems' design, design objectives, design criteria, methods of treatment, expected releases, and principal parameters used in calculating the releases of radioactive materials in liquid effluents.

The acceptance criteria for this review are:

- 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values
- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents
- GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement
- 10 CFR 50, Appendix I, Sections II.A and II.D, which set numerical guides for dose design objectives and limiting conditions for operation to meet the ALARA (as-low-as-is-reasonably-achievable) criterion

Specific review criteria are contained in SRP Section 11.2 and guidance is provided in Matrix 5 of RS-001.

Millstone 3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 11.2, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 station design relative to conformance to:

- GDC-60 is described in the FSAR Section 3.1.2.60, Control of Releases of radioactive Materials to the Environment (Criterion 60)

In all cases, the design for radioactivity control is based on:

1. The requirements of 10 CFR 20, 10 CFR 50, and 10 CFR 50, Appendix I, for normal operations and for transient situation that might reasonably be anticipated to occur.

2. 10 CFR 50.67 dose level guidelines for potential accidents of extremely low probability of occurrence.

All release paths, including ventilation and process streams, are monitored and controlled as described in FSAR Section 11.5.

Control of liquid waste effluents (FSAR Sections 11.2 and 11.5) is maintained by batch processing of all liquids, sampling before discharge, and a controlled rate of release. Liquid effluents are monitored for radioactivity and rate of flow. Radioactive liquid waste system capacities are sufficient to handle any expected transient in the processing of liquid waste.

- GDC-61 is described in the FSAR Section 3.1.2.61, Fuel Storage and Fuel Handling and Radioactive Control (Criterion 61)

Safety related components in the liquid waste management system (FSAR Section 11.2) are designed to allow periodic inspection and testing to ensure proper operation. Performance of components important to safety in the radioactive liquid system is verified by extensive process fluid analysis and continuous radiation monitoring of gaseous effluents, respectively.

The liquid waste management system areas are designed to meet the requirements of 10 CFR 20 in providing radiation shielding for operating personnel. Waste storage and processing facilities in the auxiliary building and waste disposal building are shielded to meet the requirements of 10 CFR 20 for operating personnel. Periodic surveys by health physics personnel and continuously operated radiation monitors located in areas selected to afford maximum personnel protection (FSAR Section 12.1) ensure that radiation design levels are not exceeded during lifetime of the unit.

The liquid waste management systems are designed to preclude gross mechanical failures which could lead to radioactivity releases. Floor and equipment drains are provided to collect leakage which might occur from valve stem leakoffs, pump seals, and other equipment, and to transfer the leakage to one of the building sumps for eventual processing by the liquid waste system.

As stated in FSAR Section 1.2.6:

Radioactive wastes are collected, processed, and disposed of in a safe manner complying with appropriate regulations, in particular, NRC regulations 10 CFR 20, 10 CFR 50, Appendix I, 10 CFR 61, 10 CFR 71, 49 CFR 171-178, 10 CFR 100, and General design Criteria 60 and 64 (FSAR Sections 3.1.2.60 and 3.1.2.64). There are three interrelated radioactive waste treatment systems: radioactive liquid waste, radioactive gaseous waste, and radioactive solid waste. FSAR Chapter 11 describes these systems

Additional details that define the licensing basis for the liquid waste system are described in FSAR Section 11.2, Liquid Waste Management Systems. In accordance with General Design Criterion 60, liquid management systems are provided to control, collect, process, store, recycle, and dispose of liquid radioactive waste generated as the result of normal plant operation, including anticipated operational occurrences.

Two of the design bases of the liquid waste management systems are described in FSAR Section 11.2.1. One is to control the releases of radioactive materials within the limits set forth in 10 CFR 20 and to meet the numerical design objectives of 10 CFR 50, Appendix I. The other is that General Design Criterion 61 applies with regard to provisions for suitable shielding for radiation protection of personnel under normal and postulated accident conditions.

FSAR Chapter 15, Accident Analysis addresses a radioactive liquid waste system leak or failure (Atmospheric Release) (Section 15.7.2). The analysis concludes that the radiological consequences are consistent with the guidelines of the pre-1991 version of 10 CFR 20, i.e., the whole body dose does not exceed 500 mRem to an individual at the nearest exclusion area boundary and substantially below the guidelines of 10 CFR 100.

As addressed in MPS3 Safety Evaluation Report (NUREG-1031, August 2, 1984), Section 11.2, “Liquid Waste Management System”, MPS3 liquid waste management system design is acceptable and meets the requirements of 10 CFR 20.106; 10 CFR 50.34a; 10 CFR 50, Appendix I, and GDC-60, -61, and -64; as referenced in the SRP.

The MPS3 Liquid Waste Management System was evaluated for continued acceptability to support plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005 documents the results of that review. NUREG-1838, Section 2.3B.3.47 is applicable to the Liquid Waste Management System.

2.5.6.2.2 Technical Evaluation

2.5.6.2.2.1 Introduction

The liquid waste management system is described in FSAR Section 11.2. It consists of process equipment and instrumentation necessary to collect, process, monitor, and recycle or dispose of radioactive liquid waste from the operation of MPS3. The liquid radioactive waste management system consist of the high-level waste, low-level waste, condensate demineralizer liquid waste (removed from service and no longer used), and boron recovery subsystems. The liquid waste system is designed to collect and process wastes according to source, activity, and composition of the fluids. Liquid waste is processed on a batch basis to permit optimum control and disposal of radioactive waste. Before the waste is released, samples are analyzed to determine the types and amounts of radioactivity present. On the basis of the results of the analyses, the waste is recycled for eventual reuse in the plant, retained for further processing, or released under controlled conditions to the circulating water tunnel. A radiation monitor will automatically terminate the liquid waste discharge if radiation measurements exceed a predetermined level.

2.5.6.2.2.2 Description of Analyses and Evaluations

The liquid waste management system and components were evaluated to ensure they are capable of performing their intended functions at SPU conditions. The evaluation determined whether the SPU operating conditions are enveloped by the design parameters of the existing system/components.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the liquid waste management system is within the scope of license renewal. However, the liquid waste management system flow rates, water inventory and process conditions are not changed by the SPU and are within the original design parameters of the system. The increased concentration of radionuclides within the system has an effect on the aging of systems/components bounded by current analyses and there are no system/component modifications necessary. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the liquid waste management systems at SPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.6.2.2.3 Results

The implementation of power uprate does not increase the inventory of liquid normally processed by the liquid waste management system above system capability since the system functions are not changing and the assumptions related to volume inputs remain the same.

Potentially radioactive drainage is collected in tanks and drain sumps from selected systems and components and is directed to the appropriate radwaste processing system. Liquids leaking from process systems, liquids used during cleaning activities, liquid spills from maintenance activities, and liquids generated in the radio-chemistry laboratory enter the equipment and floor drain system during all plant operating modes. The implementation of SPU does not add any new sources of potentially contaminated leakage, nor does it create any new flow paths or routes that would allow the contamination of drainage systems designed for uncontaminated fluids.

The SPU results in an increase in the equilibrium radioactivity in the reactor coolant. This change in radioactivity of the reactor coolant impacts the concentrations of radioactive nuclides in the waste disposal systems. The radiological impact of the increased activity in the waste disposal systems is detailed in Section 2.10.1, Occupational and Public Radiation Doses.

The evaluation of the liquid waste management system at SPU conditions shows conformance with 10 CFR 20.1302, insofar as the annual average concentrations of radioactive materials released at the boundary of the unrestricted area will not exceed specified values. This will be demonstrated by the continued compliance post SPU to the annual dose objective of 10 CFR 50, Appendix I, as discussed in Section 2.10.1, Occupational and Public Radiation Doses. Discharge streams will remain appropriately monitored and adequate safety features remain incorporated to preclude releases, in accordance with the offsite dose calculation manual.

The evaluation of the liquid waste management system at SPU conditions demonstrates that the MPS3 will continue to meet the current licensing basis with respect to the requirements of GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. This design capability remains unchanged by the SPU. The handling, control, and release of radioactive materials are in compliance with 10 CFR 50, Appendix I, and is described in the offsite dose calculation manual.

The evaluation of the liquid waste management system at SPU conditions demonstrates that the MPS3 will continue to meet the current licensing basis with respect to the requirements of GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement to ensure adequate safety under normal and postulated accident conditions. This design capability remains unchanged by the SPU.

The evaluation of the liquid waste management system at SPU conditions demonstrates conformance with the requirements of 10 CFR 50, Appendix I, Section II.A, which set numerical guides for dose design objectives and limiting conditions for operation to meet the “as-low-as-is-reasonably-achievable” criterion has been formalized in the technical specifications for the radioactive effluent controls program and the offsite dose calculation manual. Refer to Section 2.10.1, Occupational and Public Radiation Doses for details.

In addition to the evaluations described above, the liquid waste system was evaluated for the continued acceptability for the purpose of plant license renewal. The results of that review are found in NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005. System and system component materials of construction, operating history and programs used to manage aging effects are documented in the SER. The liquid waste system was determined to be within the scope of the license renewal and components subject to age management review are evaluated on a plant wide basis as commodities, where the generic commodity groups are described in SER Section Number 2.3B.3.47.

2.5.6.2.3 Conclusion

The evaluation has confirmed that the change in the amount of liquid waste after SPU is within the system capability, and that the increase in fission products resulting from the increased equilibrium radioactivity of the reactor coolant system does not affect the ability of the liquid waste management system to control releases of radioactive materials. The liquid waste management system will continue to meet its design functions and the requirements of 10 CFR 20.1302 and 10 CFR 50, Appendix I, Section II.A and Section II.D. MPS3 will continue to meet the current licensing basis with respect to the requirements of GDC-60 and 61. Therefore, the proposed SPU is acceptable with respect to the liquid waste management system.

2.5.6.3 Solid Waste Management Systems

2.5.6.3.1 Regulatory Evaluation

The DNC review of the solid waste management systems focused on the effects that the proposed SPU may have on previous analyses and considerations related to the design objectives in terms of expected volumes of waste to be processed and handled, the wet and dry types of waste to be processed, the activity and expected radionuclide distribution contained in the waste, equipment design capacities, and the principal parameters employed in the design of the solid waste management systems.

The acceptance criteria for this review are

- 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values.
- GDC-60, insofar as it requires that the plant design include a means to control the release of radioactive effluents.
- GDC-63, insofar as it requires that systems be provided in waste-handling areas to detect conditions that may result in excessive radiation levels.
- GDC-64, insofar as it requires that a means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and postulated accidents.
- 10 CFR 71, which states requirements for radioactive material packaging.

Specific review criteria are contained in SRP Section 11.4 and guidance is provided in Matrix 5 of RS-001.

Millstone 3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Sections 11.4, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 Station design relative to conformance to

- GDC-60 is described in the FSAR Section 3.1.2.60, Control of Releases of Radioactive Materials to the Environment (Criterion 60).

In all cases, the design for radioactivity control is based on

1. The requirements of 10 CFR 20, 10 CFR 50, and 10 CFR 50, Appendix I, for normal operations and for transient situation that might reasonably be anticipated to occur.

2. 10 CFR 50.67 dose level guidelines for potential accidents with extremely low probability of occurrence.

All release paths, including ventilation and process streams, are monitored and controlled as described in FSAR Section 11.5.

Solid wastes are prepared for offsite disposal by either compaction or solidification (FSAR Section 11.4). Solid waste is prepared for shipment by placement in properly labeled containers that meet applicable NRC and Department of Transportation dose rate requirements as detailed in 10 CFR 71, 49 CFR 170-178, and FSAR Section 11.4.

- GDC-63 is described in the FSAR Section 3.1.2.63, Monitoring Fuel and Waste Storage (Criterion 63).

  Radiation levels in the solid waste management system area of the spent fuel storage are continuously monitored by radiation detectors located around the periphery of the storage areas. Other continuously operating radiation detectors are located in the waste disposal buildings in areas best suited for alerting operating personnel of high local radiation levels. Radiation levels in excess of the present values for either of the waste storage areas initiate alarms, both locally and in the control room.

As addressed in NUREG-1031, MPS3 Safety Evaluation Report, August 2, 1984, including Supplement No. 3, dated November 11, 1985, Section 11.4, Solid Waste Management System, the MPS3 solid waste management system design is acceptable and meets the requirements, as referenced in the SRP, of 10 CFR 20.106; 10 CFR 50.34a; GDC-60, -61, and -64; and 10 CFR 71.

As stated in FSAR Section 1.2.6:

> Radioactive wastes are collected, processed, and disposed of in a safe manner complying with appropriate regulations, in particular, NRC regulations 10 CFR 20, 10 CFR 50, Appendix I, 10 CFR 61, 10 CFR 71, 49 CFR 171-178, 10 CFR 100, and General Design Criteria 60 and 64 (FSAR Sections 3.1.2.60 and 3.1.2.64). There are three interrelated radioactive waste treatment systems: radioactive liquid waste, radioactive gaseous waste, and radioactive solid waste. FSAR Chapter 11 describes these systems.

Additional details that define the licensing basis for the solid waste system are described in FSAR Section 11.4. The radioactive solid waste system is designed in accordance with the following criteria (FSAR Section 11.4.1):

1. Solid waste containers, shipping casks, and methods of packaging meet applicable federal regulations (e.g., 10 CFR 71). Wastes are to be shipped to a licensed burial site in accordance with applicable NRC (e.g., 10 CFR 61) and Department of Transportation regulations (e.g., 49 CFR 171-178). Solid waste treatment design is in compliance with the

relevant requirements of 10 CFR 20, Sections 105 and 106 (version prior to January 1, 1994), as it relates to radioactivity in effluents to unrestricted areas.

2. The filling of containers, the dewatering, the solidification, and/or the storage of radioactive solid wastes conforms to 10 CFR 20 and 10 CFR 50 requirements and RG 8.8 guidelines in terms of "as-low-as-is-reasonably-achievable" (ALARA) doses to plant personnel and the general public.

Also, the filling of containers and the storage of radioactive solid waste conforms with 10 CFR 20 and 10 CFR 50 requirements. Packages meet shipping regulations of 49 CFR 171-178 and 10 CFR 71 as applicable (Section 11.4.2.4). Solidified boron and waste evaporator bottoms are shipped in accordance with NRC regulations 10 CFR 20, 10 CFR 50, and 10 CFR 71, and Department of Transportation regulations 49 CFR 171 through 178 (FSAR Section 11.4.2.2.1).

The shipment of radioactive solid waste conforms with 10 CFR 20, 10 CFR 50, and 10 CFR 61 requirements and 10 CFR 71 and 49 CFR 171 through 178. Solid waste is transferred either directly to a licensed disposal contractor or to a common carrier for delivery to a licensed burial site or secondary processor as appropriate (MPS3 Section 11.4.2.6).

The MPS3 Solid Waste Management System was evaluated for continued acceptability to support plant license renewal. NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3," dated August 1, 2005 documents the results of that review. NUREG-1838, Section 2.3B.3.50 is applicable to the Solid Waste Management System.

2.5.6.3.2 Technical Evaluation

2.5.6.3.2.1 Introduction

The solid waste management system is described in FSAR Section 11.4. Materials handled as solids may include any of the following: concentrated waste solutions from the waste evaporator, concentrated boric acid discarded from the boron evaporator in the boron recovery system, spent resin from radioactive process demineralizers and exchangers, spent filter cartridges, and miscellaneous sludges. In accordance with station operating procedures, potentially radioactive sludge, oily wastes, and solids are collected and processed according to physical and chemical properties and radioactive concentrations.

The solid waste management system design functions are to collect, hold, process, dewater or solidify, package, handle, and temporarily store radioactive materials prior to their shipment offsite and ultimate disposal.

Components associated with the solid waste processing system are the demineralizers, spent resin hold tank, spent resin dewatering tank, and spent resin pumps. To ensure that personnel exposure is minimized, all phases of the solidification process incorporate ALARA design features and operational procedures.

The spent resin hold tank retains the spent resin which has been used to remove chemical impurities and radioactive contamination from the reactor coolant, the chemical and volume control system, the spent fuel pool, boron recovery, and liquid waste processing system.

Normally, the tank is filled over a long period of time, the contents are allowed to decay and are then emptied prior to receiving any additional resin. However, the contents can be removed at any time if sufficient shielding is provided for the disposable waste shipping container.

2.5.6.3.2.2 Description of Analyses and Evaluations

The solid waste management system and components were evaluated to ensure they are capable of performing their intended functions at SPU conditions. The evaluation determined whether the SPU operating conditions are enveloped by the design parameters of the existing system/components.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

In addition to the evaluations described above, the solid waste system was evaluated for the continued acceptability for the purpose of plant license renewal. The results of that review are found in NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Units 2 and 3, dated August 1, 2005. The SER documents system and system component materials of construction, operating history and programs used to manage aging effects. The solid waste system was determined to be within the scope of the license renewal and components subject to age management review were evaluated on a plant-wide basis as commodities. The generic commodity groups are described in SER Section 2.3B.3.50.

2.5.6.3.2.3 Results

The proposed SPU has no effect on the generation of solid waste volume from the primary and secondary systems since the system functions are not changing and the assumptions related to volume inputs remain the same. The SPU results in increases in the equilibrium radioactivity in the reactor coolant which does not exceed existing limits. This change in radioactivity of the reactor coolant impacts the concentrations of radioactive nuclides in the waste disposal systems. The impact of the increased activity in the waste disposal systems is detailed in Section 2.10.1, Occupational and Public Radiation Doses.

Since the annual average concentrations of radioactive materials released at the boundary of the unrestricted area will not exceed specified values, the evaluation of the solid waste management system at SPU conditions demonstrates concurrence with 10 CFR 20.1302. This is demonstrated by the continued compliance, post-SPU, to the annual dose objective of 10 CFR 50, Appendix I, as discussed in Section 2.10.1, Occupational and Public Radiation Doses. Discharge streams will remain appropriately monitored and adequate safety features remain incorporated to preclude excessive releases.

The evaluation of the solid waste management system at SPU conditions demonstrates that MPS3 will continue to meet the current licensing basis requirements of GDC-60, which requires that the plant design include means to control the release of radioactive effluents. This design capability remains unchanged by the SPU, and therefore the current design capability remains acceptable. The handling, control, and release of radioactive materials are in compliance with 10 CFR 50, Appendix I.

The evaluation of the solid waste management system at SPU conditions demonstrates that MPS3 will continue to meet the current licensing basis requirements of GDC-63, which requires that systems be provided in waste handling areas to detect conditions that may result in excessive radiation levels and to initiate appropriate safety actions. This design capability remains unchanged by the SPU, and therefore the current design capability remains acceptable. Radiation monitors and alarms are provided as required to warn personnel of impending excessive levels of radiation or airborne activity.

The evaluation of the solid waste management system at SPU conditions demonstrates that the MPS3 Station will continue to meet the current licensing basis requirements of GDC-64, which requires that a means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences and postulated accidents. This design capability remains unchanged by the SPU, and therefore the current design capability remains acceptable. Radioactivity levels contained in the effluent discharge paths in the environs are continually monitored during normal and accident conditions by the station radiation monitoring system and by the radiation protection program for MPS3 Station.

The evaluation of the solid waste management system at SPU conditions demonstrates conformance with the requirements of 10 CFR 71, insofar as the radioactive material packaging accounts for the maximum dose rate allowed on the surface of the container by shielding of the package in which the container is shipped. Packaging, shielding, and handling of radioactive material are not changed by SPU; thus, compliance with 10 CFR 71 is not affected.

As discussed above, the solid waste management system is within the scope of license renewal. However, the solid waste management volumes, storage, and handling conditions are impacted by the SPU, but remain below system limits. The increased concentration of radionuclides within the system has no impact on the aging of systems/components and there are no system/component modifications necessary. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The changes associated with operating the solid waste management systems at SPU conditions do not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

With the exception of the possible wastes generated through fuel cleaning required as a result of crud induced power shift (CIPS), the quantity of other solid wastes generated at SPU conditions is not anticipated to increase appreciably relative to pre-SPU levels, because SPU will not significantly impact installed equipment operation or maintenance.

Implementation of SPU is anticipated to increase the potential for occurrence of the CIPS phenomena. Details associated with the fuel cleaning process proposed to manage/preclude CIPS require finalization however, it is anticipated that, in every refueling outage, this process will result in some amount of solid wastes in the form of filters loaded with radioactive crud deposits. Plans are to store these wastes in the spent fuel pool for a period of time based on filter material radiation limitations or disposal limitations of 10 CFR 61 (licensing requirements for land disposal of radioactive waste).

2.5.6.3.3 Conclusion

The SPU has no significant impact on the solid waste management system. No modifications to the solid waste management system are required for SPU. The effect of the increase in fission product resulting from the increased equilibrium radioactivity of the reactor coolant system and amount of solid waste on the ability of the solid waste management system to process the waste has been evaluated and the solid waste management system meets its design functions following implementation of the proposed SPU.

The solid waste management system continues to meet the requirements of 10 CFR 20.1302 and 10 CFR 71. MPS3 will continue to meet the current licensing basis with respect to the requirements of GDC-60, -63 and -64. Therefore, the proposed SPU is acceptable with respect to the solid waste management system.

2.5.7 Additional Considerations

2.5.7.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

2.5.7.1.1 Regulatory Evaluation

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions assuming a single failure. DNC review focused on increases in emergency diesel generator electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function.

The acceptance criteria for emergency diesel engine fuel oil storage and transfer system are based on

- GDC-4, insofar as it requires that SSCs important to safety be protected against dynamic effects, including missiles, pipe whip, and jet impingement forces associated with pipe breaks.
- GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions.
- GDC-17, insofar as it requires onsite power supplies to have sufficient independence and redundancy to perform their safety functions, assuming a single failure.

Specific review criteria are contained in SRP Section 9.5.4, and guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Section 9.5.4, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. Specifically, the adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Section 3.1.2.

- GDC-4 is described in FSAR Section 3.1.2.4, General Design Criteria 4 – Environmental and Missile Design Bases.

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-5 is described in FSAR Section 3.1.2.5, General Design Criteria 5 – Sharing of Structures, Systems, and Components.

  There are no components of the EDG fuel oil storage and transfer system that are shared between MPS3 and MPS2.

- GDC-17 is described in the FSAR Section 3.1.2.17, General Design Criteria 17 - Electric Power Systems.

  Two connections to the offsite power system are provided. The preferred offsite connection is a backfeed through the main and normal station service transformers with the generator breaker open. The alternate offsite connection is through the reserve station service transformers. Each offsite source has 100 percent capacity for all emergency and normal loads during all phases of operation plus, as an alternate offsite source for minimum post-accident loads, the capacity to supply Millstone Unit 2 GDC-17 requirements through the NSST or RSST.

  Two onsite power systems are provided. Each system has an emergency diesel generator. Each diesel generator has 100 percent capacity for the emergency loads in the event of the postulated accidents or if required for reactor cooldown.

  The design of the electrical system (FSAR Chapter 8) conforms to Criterion 17.

Additional details that define the licensing basis are described in FSAR Section 9.5.4, Emergency Generator Fuel Oil Storage and Transfer System.

Technical Specifications 3.8.1.1.b.2 and 3.8.1.2.b.2 require a minimum volume of 32,760 gallons be contained in each diesel generator fuel storage system. This capacity ensures that a minimum usable volume (29,180 gallons) is available to permit operation of each of the diesel generators for approximately three days with the diesel generators loaded to the 2,000 hour rating of 5335 kW. The ability to cross-tie the diesel generator fuel oil storage tanks ensures that one diesel generator may operate up to approximately six days. Additional fuel oil can be supplied to the site within 24 hours after contacting a fuel oil supplier.

The emergency diesel engine fuel oil storage and transfer system was evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.3A.3.36 and 2.3B.3.43 are applicable to the fuel oil storage and transfer system.

2.5.7.1.2 Technical Evaluation

2.5.7.1.2.1 Introduction

The emergency diesel engine fuel oil storage and transfer system is described in the FSAR Section 9.5.4. The function of the fuel oil storage and transfer system is to provide a separate and independent fuel oil supply train for each diesel engine to permit operation of a single diesel engine at ESF load requirements. Each flow path consists of a fuel oil storage tank, two 100 percent capacity fuel oil transfer pumps, a strainer, a day tank, and piping to each respective diesel engine. Each day tank has two supply and one return connections to the fuel oil injection system, mounted integrally, and provided with its respective diesel engine.

The function of the fuel oil storage tank is to provide bulk storage for the fuel oil that is used by the EDG under all plant operating conditions and during all design basis events.

The function of the fuel oil day tank is to provide an immediate source of fuel oil to the EDG.

The function of the fuel oil transfer pump is to transfer fuel oil from the storage tank to the day tank and have sufficient capacity to fill the day tank with the emergency generator running at rated load and speed.

The function of the piping with two normally locked-closed valves between the two emergency generator fuel oil supply headers is to facilitate the use of either storage tank to provide fuel oil to either emergency generator.

The function of the strainers is to ensure that the fuel oil delivered to the day tank meets the diesel generator manufacturer's standards of purity.

2.5.7.1.2.2 Description of Analysis and Evaluations

The emergency diesel generator fuel oil and transfer system and its components were evaluated to ensure they are capable of performing their intended function at SPU conditions. The evaluation is based on the system's required design functions, and a comparison between the existing equipment ratings and the anticipated operating requirements at SPU conditions.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal safety evaluation report for the emergency diesel engine fuel oil storage and transfer system. As shown in Section 2.5.7.1.1, the emergency diesel engine fuel oil storage and transfer system is within the scope of license renewal. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with operation of the fuel oil storage and transfer system at SPU condition, and the SPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.7.1.2.3 Results

The emergency diesel engine fuel oil storage and transfer system has been evaluated. Review of the electrical loads for operation at the SPU conditions indicates that there are no additional loads or changes in load sequence or durations required to the existing emergency diesel generators. Therefore, there is no impact to the existing emergency diesel generator loading analysis or fuel oil quantity and consumption rate analysis, which is based on the 2000-hour rating of 5335 kW, and bounds the SPU conditions. The emergency diesel generator electrical loading is discussed in LR Section 2.3.3, AC Onsite Power System.

Since there are no changes, the independence and redundancy features of the system are not impacted by SPU, and it continues to meet the MPS3 current licensing basis with respect to the requirements of GDC-4, GDC-5 and GDC-17. The design for missile protection and protection against dynamic effects associated with the postulated rupture of piping will be maintained.

2.5.7.1.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the emergency diesel fuel oil storage and transfer system. DNC concludes that the evaluation has adequately accounted for SPU impact on the emergency diesel engine fuel oil storage and transfer system. The fuel oil and transfer system will continue to provide an adequate amount of fuel oil to the emergency diesel generators and continue to meet the MPS3 current licensing bases with respect to the requirements of GDC-4, GDC-5 and GDC-17 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU is acceptable with respect to the fuel oil storage and transfer system.

2.5.7.2 Light Load Handling System (Related to Refueling)

2.5.7.2.1 Regulatory Evaluation

The light load handling system (LLHS) includes components and equipment used in handling new fuel at the receiving station and the loading of spent fuel into shipping casks. The DNC review covered the avoidance of criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures. The DNC review focused on the effects of the new fuel on system performance and related analyses.

The acceptance criteria are based on:

- GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement and with suitable shielding for radiation protection, and
- GDC-62, insofar as it requires that criticality be prevented.

Specific review criteria are contained in SRP Section 9.1.4 and guidance is provided in Matrix 5 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed against the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), Section 9.1.4, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 was measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria (GDC) is discussed in FSAR Sections 3.1.1 and 3.1.2. Specifically, the adequacy of the MPS3 design relative to:

- GDC-61, Fuel Storage and Handling and Radioactive Control, is described in FSAR Section 3.1.2.61.

  The new and spent fuel storage areas are designed to meet the requirements of 10 CFR 20 in providing radiation shielding for operating personnel during new and spent fuel transfer and storage. New and spent fuel handling systems are designed to preclude gross mechanical failures which could lead to significant radioactivity releases. Radioactive gases and particulates, which may leak from spent fuel, are collected and treated by the building ventilation filtration system.

- GDC-62, Prevention of Criticality in Fuel Storage and Handling, is described in FSAR Section 3.1.2.62.

  Criticality is prevented in the new fuel storage racks by a combination of geometry and poison material as described in FSAR Sections 9.1.1 and 4.3.2.6. Criticality is prevented in the spent fuel storage area by the physical separation of fuel assemblies, limits on the enrichment, burnup and decay times of the fuel, and the use of fixed neutron poisons. Soluble boron in the spent fuel pool water is credited for certain accident conditions. FSAR Sections 9.1.1 and 9.1.2 discuss criticality prevention in more detail.

The cranes, new and spent fuel storage racks, spent fuel pool and liner, and cask washdown area were evaluated for continued acceptability regarding plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3”, dated August 1, 2005, documents the results of that review. NUREG-1838, Section 4.7B.1 is applicable for the spent fuel cask crane. NUREG-1838, Sections 2.4B.2.4 and 3.5B.2.3.5 are applicable for new and spent fuel storage racks, spent fuel pool and liner, and cask washdown area.

2.5.7.2.2 Technical Evaluation

2.5.7.2.2.1 Introduction

The fuel handling system is described in FSAR Section 9.1.4. The fuel handling system consists of equipment used for conducting the refueling operation in a safe manner and includes the following components and structures:

- New fuel receiving crane
- New fuel handling crane
- New fuel elevator
- Spent Fuel Bridge and hoist
- Fuel transfer system
- Refueling machine
- Spent fuel cask crane
- New fuel storage vault
- Spent fuel storage pool
- Fuel transfer canal
- Refueling cavity
- Fuel transfer tube

The following design bases apply to the fuel handling system:

1. Fuel handling devices have provisions to avoid dropping or jamming of fuel assemblies during transfer operation.
2. Handling equipment has provisions to avoid dropping of fuel handling devices during the fuel transfer operation.
3. Handling equipment used to raise and lower spent fuel has a limited maximum lift height so that the minimum required depth of water shielding is maintained.
4. The fuel transfer system, where it penetrates the containment, has provisions to preserve the integrity of the containment pressure boundary.

5. Criticality during fuel handling operations is prevented by the geometrically safe configuration of the fuel handling equipment.

6. In the event of a safe shutdown earthquake, handling equipment cannot fail in such a manner so as to damage seismic Category I equipment or spent fuel assemblies.

7. The inertial loads imparted to the fuel assemblies or core components during handling operations are less than potential damage-causing loads.

8. Physical safety features are provided for personnel who operate handling equipment.

9. The spent fuel shipping cask crane is physically prevented from bringing the spent fuel shipping cask over the spent fuel pool.

10. Provisions have been included such that a spent fuel transfer cask drop is not credible. Therefore, there will be no damage to safety related equipment or spent fuel assemblies.

11. The new fuel handling crane is equipped with interlocks such that it cannot carry a load over the spent fuel pool. Administrative controls may be used in lieu of crane interlocks and physical stops for handling fuel racks, spent fuel pool gates, or loads less than 2200 lb.

12. Maximum kinetic energy for any load moved by light load handling systems above the spent fuel pool does not exceed the energy of a fuel assembly dropped from its normal handling height.

2.5.7.2.2.2 Description of Evaluation

This technical evaluation covers the impact of SPU on the avoidance of criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and acceptable personnel radiation exposure.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The fuel handling license renewal boundary only includes cranes, hoists or lifting devices categorized under NUREG-0612. As stated earlier, the most frequently used component, MPS3 spent fuel cask crane, was evaluated for continued acceptability regarding plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3”, dated August 1, 2005, documents the results of the that review. NUREG-1838, Section 4.7B.1 is applicable for the spent fuel cask crane.

SPU activities are not adding any new components within the existing license renewal scoping evaluation boundaries nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating at SPU conditions do not add new or previously unevaluated materials to the system. System components internal or external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.7.2.2.3 Results

The fuel design that will be used for the stretch power uprate is currently in service at MPS3, 17 x 17 RFA-2. The fuel has been designed to be compatible with the fuel handling equipment and refueling equipment. The fuel assembly functional requirements and design criteria remain unchanged for the stretch power uprate. The fuel handling system for MPS3 has been used successfully with this fuel design. Since there are no changes to the fuel assembly weight, the probability of any fuel handling system components resulting in a fuel handling accident is not changed. The fuel handling equipment will be operated in accordance with current requirements for maintaining a minimum spent fuel pool water level above fuel assemblies during fuel handling operations. Therefore, it is concluded that the fuel handling system used to handle nuclear fuel would continue to meet the acceptance criterion of GDC-61 with respect to providing adequate confinement of radioactive material and providing suitable shielding from radiation for personnel involved in nuclear fuel handling operations.

With respect to criticality accidents, the analyses and evaluations are presented in LR Section 2.8.6.2, Spent Fuel Storage. The criticality analyses assume a new fuel assembly is inadvertently placed in the most reactive pool location, simulating a dropped fuel assembly or a fuel-mispositioning event, and the resulting analyses demonstrate that Keff remains less than 0.95. Therefore, the acceptance criteria of GDC-62 will continue to be met with respect to preventing criticality by appropriate management of spent fuel storage (i.e. burnup vs. storage rack location) and maintaining the required minimum soluble boron concentration in the spent fuel pool.

2.5.7.2.3 Conclusion

DNC has reviewed the assessment of the effects of the new fuel and spent fuel on the ability of the LLHS to avoid criticality accidents and concludes that DNC has adequately incorporated the effects of the new fuel and spent fuel in the analyses. Based on this review, DNC further concludes that the LLHS will continue to meet the requirements of GDCs -61 and -62 for radioactivity releases and prevention of criticality accidents. Therefore, DNC finds the proposed SPU acceptable with respect to the LLHS.

2.5.8 Additional Review Areas (Plant Systems) Circulating Water Systems

2.5.8.1 Circulating Water System

2.5.8.1.1 Regulatory Evaluation

NRC Review Standard RS-001 does not explicitly call out the SRP or any other guidance documentation related to the capability of the circulating water system to provide a continuous supply of cooling water to the main condenser to remove heat rejected by the turbine cycle. The DNC review focused on changes to the amount of heat absorbed by the circulating water system from increased heat rejection from the main condenser and other systems due to the higher SPU power level. The evaluation also includes the impact on the circulating water components to ensure that the system accomplishes its design functions after implementation of SPU. Specific temperature limits for the circulating water discharged from MPS3 are contained in the site NPDES permit.

MPS3 Current Licensing Basis

As discussed in FSAR 10.4.5.1, the circulating water system is a once-through cooling water design utilizing an onshore Niantic Bay intake and a quarry surface discharge. The circulating water system is not safety-related except for the circulating water discharge tunnel (QA Category I and Seismic Category I) and portions of the intake structure. FSAR Section 3.8.4 discusses the Circulating Water Discharge and intake structure. The circulating water system is designed to remove 7.5E9 BTU/hr of waste heat from the power conversion cycle. The rejected heat is transferred to the circulating water as it flows through the condenser.

The site NPDES permit (Permit No. CT0003263) limits MPS3 circulating water discharge to the quarry (Discharge Serial No. 001-C) to a maximum temperature of 98°F and a maximum increase from the Niantic Bay intake to discharge to the quarry to 24°F. In addition, the site NPDES permit limits the maximum temperature of the discharge to Long Island Sound at the quarry cut (Discharge Serial No. 001-1) to 105°F and limits the maximum temperature increase at the quarry cut discharge to 32°F above the Niantic Bay intake. For unusual conditions, the NPDES permit limits the maximum differential temperature increase at the quarry cut above the intake water temperature to 44°F for a period not exceeding 24 hours.

The circulating water system was evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.3B.3.1 and 3.3B.2.3.1 are applicable to the circulating water system.

2.5.8.1.2 Technical Evaluation

2.5.8.1.2.1 Introduction

The function of the circulating water system is to provide a reliable supply of water to condense the steam exhausted from the low-pressure turbines and turbine bypass control valves as well as to provide dilution of liquid discharges prior to release. The water source and heat sink for the circulating water system is the Long Island Sound. The circulating water system is a once-through cooling water design utilizing an onshore Niantic Bay intake and a quarry surface discharge. Debris-free salt water is provided to the main condenser where waste heat from the thermal power cycle is collected for removal to the quarry. The circulating water system consists of six circulating water pumps, piping, valves, and expansion joints. The pumps take suction from the intake structure, which is equipped with traveling screens. Circulating water is pumped through the main condensers to remove heat rejected from the steam cycle. The water is discharged to the Long Island Sound via the discharge tunnel and quarry cut.

The associated circulating water systems are the traveling screen wash and disposal system and the vacuum priming system. The traveling screen wash and disposal system removes debris from the seawater used as cooling water in the unit. The vacuum priming system initially primes and continuously removes air from the circulating water lines, the condenser water boxes, and the circulating water discharge tunnel and outfall structure to create and maintain a siphon in the tube side of each of the main condensers and to ensure that all tubes are filled.

2.5.8.1.2.2 Description of Analyses and Evaluations

The circulating water system and its components were evaluated to ensure they are capable of performing their intended function at SPU conditions. The circulating water system was conservatively evaluated for a NSSS power level of 3666 MWt. The evaluation reviewed the circulating water system to determine whether the existing flow rate is capable of removing the higher steam cycle heat duty at SPU conditions.

The increased heat rejection to the circulating water system from the turbine cycle heat loads at SPU conditions raises the system operating temperature downstream of the condenser. Heat loads during normal plant full power operation and during plant load changes which cause a turbine bypass directly to the condenser were utilized in the evaluation.

The existing component design temperatures and pressures were reviewed to confirm that the higher operating temperatures are bounded by the component designs. The higher circulating water outlet temperatures were also reviewed against the site NPDES existing permit.

Other evaluations related to the circulating water system, piping and components are included in the following sections:

- Liquid waste effluent discharge to the discharge canal - Section 2.5.6.2, Liquid Waste Management Systems
- Protection against flooding due to a failure in the circulating water system - Section 2.5.1.1.3, Circulating Water System (CWS)
- Circulating water system instrumentation - Section 2.4, Instrumentation and Controls
- Heat removal and cooling of the main condenser – Section 2.5.5.2, Main Condenser

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal safety evaluation report for the circulating water system. As shown in Section 2.5.8.1.1, the circulating water system is within the scope of license renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with operation of the circulating water system at SPU conditions, and the SPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.5.8.1.2.3 Results

CLTP operating circulating water system flow rates are adequate to remove the increased heat rejected by the steam cycle at SPU conditions, as demonstrated by the SPU heat balances that predict the expected plant electric power output at the SPU NSSS power level of 3666 MWt. No physical changes are required in the circulating water system. Therefore, the current circulating water system flow rate is acceptable for SPU conditions.

The outlet temperature of the circulating water system is higher at SPU conditions due to the higher rejection from the condenser. With the Niantic Bay intake temperature at its design maximum temperature of 75°F, the discharge temperature of the circulating water discharge to the quarry increases to 94.5°F during normal proposed SPU 100 percent power operation. The temperature rise across the condenser is 19.5°F. The circulating water discharge temperature to the quarry for normal operation is below the NPDES discharge limit of 98°F at Discharge Serial Number 001-C. The differential increase at Discharge Serial Number 001-C above the intake water temperature during normal operation is below the NPDES permit limit of 24°F.

Operation of the turbine bypass system during the design basis load rejection produces a main condenser circulating water outlet temperature of 101°F, which represents a temperature differential of 26°F above the intake water temperature of 75°F. This discharge temperature and temperature differential are bound by the NPDES limitations to the Long Island Sound at quarry cut Discharge Serial Number 001-1 (105°F and 32°F, respectively).

Operating pressures and flow rates within the system do not change with implementation of SPU since the current flow rates are acceptable and the circulating water pumps continue to operate at the same flow and discharge head at SPU conditions. The design temperatures and pressures of the circulating water piping and components are acceptable for SPU operating conditions and are bounded by original design parameters.

The current capacity of the circulating water vacuum priming system is acceptable for SPU operation. The circulating water flow rate does not change at SPU conditions. Therefore, the only impact on the circulating water air release rate is the temperature increase downstream of the condenser. The current capacity of the vacuum priming system envelopes the slight increase in the air release rate.

Liquid wastes are released, after appropriate cleaning and filtering, to the circulating water discharge canal with appropriate monitoring. See Section 2.5.6.2, Liquid Waste Management Systems, for details.

2.5.8.1.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the circulating water system. DNC concludes that the evaluation of the circulating water system has adequately accounted for the ability of the circulating water system to remove heat rejected from the turbine cycle at SPU conditions. The current design of the circulating water system provides a reliable supply of water at SPU conditions to condense the steam exhausted from the low pressure turbines. The current design of the system and its components accommodates the higher condenser duty and higher temperatures at SPU conditions. Based on this, the circulating water system will continue to meet the MPS3 current licensing basis. Therefore, DNC finds the proposed SPU is acceptable with respect to the circulating water system.

2.6 Containment Review Considerations

2.6.1 Primary Containment Functional Design

2.6.1.1 Regulatory Evaluation

The containment encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident.

The DNC review covered the pressure and temperature conditions in the containment due to a spectrum of postulated LOCAs and secondary system line-breaks.

The acceptance criteria for primary containment functional design are based on:

1. GDC-16, insofar as it requires that reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment;

2. GDC-50, insofar as it requires that the containment and its internal components be able to accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA;

3. GDC-38, insofar as it requires that the containment heat removal system(s) function to rapidly reduce the containment pressure and temperature following any LOCA and maintain them at acceptably low levels;

4. GDC-13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation and accident conditions; and

5. GDC-64, insofar as it requires that means be provided for monitoring the plant environs for radioactivity that may be released from normal operations and postulated accidents.

Specific review criteria are contained in SRP Section 6.2.1.1.A and guidance provided in Matrix 6 of RS-001

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants," SRP 6.2.1.1.A, Rev. 2, July 1981.

As noted in the FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to:

- GDC-16 is described in FSAR Section 3.1.2.16.

  A steel-lined reinforced concrete containment structure, maintained at sub-atmospheric pressure, encloses the entire reactor coolant system with an essentially leak-tight barrier, as described in FSAR Section 6.2.1. The containment structure and the engineered safety features are designed to withstand internal and external environmental conditions that may reasonably be expected during the life of the unit and to ensure that the short and long term conditions following a LOCA do not exceed the design values. Following a design basis accident (DBA), the containment heat removal systems reduce the containment pressure, as described in FSAR Sections 6.2.1 and 6.2.2. Most of the leakage from the containment structure is collected and processed through the supplementary leak collection and release system, described in FSAR Section 6.2.3. This process reduces the amount of radioactivity released to the environment.

- GDC-50 is described in FSAR Section 3.1.2.50.

  The containment structure is designed with a leakage rate shown in FSAR Table 1.3-3. The containment is designed to withstand, by a sufficient margin, loads above those that are conservatively calculated to result from a DBA as discussed in FSAR Section 6.2.1.

- GDC-38 is described in FSAR Section 3.1.2.38

  Heat is removed from the containment structure following a LOCA by the containment depressurization systems, which consist of the quench spray system and the containment recirculation system (FSAR Section 6.2.2). The quench spray system, consisting of two 100-percent capacity subsystems, transfers water from the refueling water storage tank to two parallel 360-degree spray headers. The quench spray system transfers heat from the containment atmosphere to water on the containment structure floor. The containment recirculation system, which consists of two 100-percent capacity subsystems (each consisting of two pumps, two coolers, and two common 360-degree spray headers), transfers heat from the water collected in the containment structure sump to the service water system (FSAR Section 9.2.1) via the containment recirculation coolers. The quench spray pumps and the containment recirculation pumps and coolers are located in the engineered safety features building (FSAR Section 3.8).

  The containment depressurization systems are designed so that no single active failure in the short term or no single active or passive failure in the long term impairs their ability to perform their safety function. Redundant components are isolated, physically and electrically. Each subsystem is connected to a separate electrical bus which can be connected to either offsite or onsite power.

- GDC-13 is described in FSAR Section 3.1.2.13.

  Instrumentation and controls are provided to monitor and control neutron flux, control rod position, temperatures, pressures, flows, and levels as necessary to assure that adequate plant safety can be maintained. Instrumentation is provided in the reactor coolant system, steam and power conversion system, the containment, engineered safety features systems, and other auxiliaries. Parameters that must be provided for operator use under normal operating and accident conditions are indicated in proximity with the controls for maintaining the indicated parameter in the proper range.

  The quantity and types of process instrumentation provided ensures safe and orderly operation of all systems over the full design range of the plant. FSAR Chapter 7 provides a detailed discussion of the instrumentation and control systems. FSAR Appendix 7.5A provides the deviations from RG 1.97, Revision 2.

- GDC-64 is described in FSAR Section 3.1.2.64.

  The containment atmosphere is monitored during normal and transient operations of the reactor plant by the containment structure particulate and gas monitor located in the upper level of the auxiliary building (FSAR Section 12.3.4) or by grab sampling. Normal unit effluent discharge paths are monitored during normal plant operation by the ventilation particulate samples and gas monitors in the auxiliary building and engineered safety buildings (FSAR Section 11.5). After a postulated accident, the safety related ventilation vent monitors and the safety related Supplementary Leak Collection and Release System monitors are used to monitor the effluents from spaces contiguous to the containment structure including the areas that contain loss-of-coolant accident fluids. In addition, the service water outlet from each pair of containment recirculation coolers is monitored to ensure that any leakage of radioactive fluids into the service water system is detected (FSAR Section 11.5). Radioactivity levels in the environs are controlled during normal and accident conditions by the various radiation monitoring systems (FSAR Sections 11.5 and 12.3.4) and monitored by the collection of samples as part of the offsite radiological monitoring program.

The MPS3 containment, recirculation spray system, and quench spray system were evaluated for the continued acceptability for the purpose of plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, documents the results of that review. The containment is addressed in Sections 2.4B.1 and 3.5B.2.2.1, the recirculation spray system is discussed in Sections 2.3.B.2.1 and 3.2B.2.3.1, and the quench spray system is discussed in 2.3B.2.2 and 3.2B.2.3.2 of NUREG-1838.

2.6.1.2 Technical Evaluation

2.6.1.2.1 Introduction

The evaluation of the design basis LOCA and secondary MSLB events relative to containment peak pressure and temperature response was completed to demonstrate the acceptability of the containment heat removal system to mitigate the consequences of a LOCA or MSLB inside containment and to support the SPU program operation. This evaluation is documented in the subsections below.

The containment response analysis demonstrates the acceptability of the containment heat removal systems to mitigate the consequence of a spectrum of large LOCA and MSLB events inside the containment. The impact of LOCA and MSLB M&E releases on the containment pressure and temperature are addressed to assure that the containment pressure and temperature remain below their respective design limits. The systems must also be capable of maintaining the EQ parameters to within acceptable limits at the SPU program conditions.

2.6.1.2.2 Loss of Coolant Accident

The long-term LOCA M&E releases are described in the FSAR Section 6.2.1.3 and LR Section 2.6.3.1. To demonstrate the acceptability of the containment safeguards systems to mitigate the consequences of a hypothetical large-break LOCA (LBLOCA), the long-term LOCA M&E releases were used as input to the containment integrity analysis. The containment safeguards systems must be capable of limiting the peak containment pressure to less than the design pressure, and limiting the temperature excursion to less than the EQ acceptance limits.

The Millstone Unit 3 containment pressure and temperature response to LBLOCA was analyzed using the GOTHIC computer code and the NRC-approved analysis methodology described in topical report DOM-NAF-3-0.0-P-A (Reference 1). A spectrum of mass and energy release rates are considered that represents a limiting set of break sizes and locations in order to demonstrate that the containment design pressure and temperature limits will not be exceeded following a LBLOCA inside the containment.

The NRC's safety evaluation dated August 30, 2006 (Reference 2), contained the following conditions regarding the use of topical report DOM-NAF-3-0.0-P-A:

1. Prior to the implementation of the GOTHIC post-reflood mass and energy methodology contained in this topical report for North Anna 1 and 2, Millstone 2 and 3, and Kewaunee, the licensees shall perform benchmarking similar to the one performed for Surry 1 and 2 to ensure conservative values are calculated; and

2. The GOTHIC NPSHA methodology contained in this topical report cannot be used for other plants that do not credit containment overpressure to calculate NPSHA in their licensing bases.

For MPS3, DNC has bench-marked the GOTHIC post-reflood mass and energy methodology for MPS3. The benchmarking included comparisons to the current containment analysis results based on the LOCTIC code and other generic containment analyses applicable to Millstone Unit 3. It confirmed that the methodology will calculate conservative values, and was conducted in a manner similar to the one performed for Surry 1 and 2. The MPS3 containment analyses were performed within the envelope of all GOTHIC code and DNC methodology limitations. The GOTHIC NPSHA methodology will not be utilized for MPS3, because the MPS3 licensing basis does not credit containment overpressure to determine NPSHA.

The Topical Report and the NRC SER were based on GOTHIC version 7.2. The SPU analysis used GOTHIC version 7.2a, which is functionally identical to version 7.2. Version 7.2a incorporates error corrections identified in GOTHIC version 7.2.

2.6.1.2.2.1 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The initial containment atmospheric conditions are chosen consistent with the guidance in NUREG-0800 Sections 6.2.1 and 6.2.1.1.A. The assumptions vary depending on the containment design limit that is being verified. For the MPS3 containment, the influence of the containment initial conditions, as documented in Table 3.6.1 of DOM-NAF-3-0.0-P-A (Reference 1), was confirmed by running parametric studies using the MPS3 specific GOTHIC model that assumes a Technical Specifications limit on total pressure and by varying one input while keeping the others constant. The most conservative settings for containment integrity analyses are summarized below. The assumption of maximum temperature for the limiting LOCA Peak Pressure differs from Table 3.6.1 of DOM-NAF-3.0.0-P-A (Reference 1). This is discussed in additional detail in Section 2.6.1.2.2.3.

Analysis	Pressure	Temperature	Humidity
LOCA Peak Pressure	MAX	MAX	MIN
LOCA Peak Temperature	MAX	MAX	MAX
Containment Depressurization	MAX	MAX	MAX

The term MAX indicates that the parameter is set to the largest allowable operating value (accommodating instrument uncertainty), while MIN indicates that the parameter is set to the smallest allowable operating value. For example, the initial containment conditions that yield the highest peak calculated containment pressure are the maximum pressure, maximum temperature, and minimum relative humidity.

The Quench Spray system is assumed to be initiated when containment pressure exceeds 24.7 psia and delivers spray to the containment atmosphere 70.2 seconds later. The QSS spray is assumed to be 100°F liquid from the RWST.

The Recirculation Spray system is assumed to start when the RWST level reaches the low level alarm setpoint.

The analytical initial condition ranges that are used in the containment integrity analysis are as follows:

1. Initial containment pressure of 14.2 psia to 10.4 psia
2. Initial containment temperature of 75°F to 125°F
3. Initial containment Relative Humidity range of 0 percent to 100 percent
4. Service water (ultimate heat sink) temperature of up to 80°F
5. Refueling water storage tank temperature of up to 100°F

Application of Single-Failure Criterion

A single failure analysis is not necessary for the peak containment pressure evaluation since the peak pressure for each break case analyzed occurs early in the transient, before any active ESF system affects the results. For the verification of the remaining containment design criteria, the following single failures have been evaluated:

- Minimum ESF (diesel generator failure resulting in loss of one ESF train, i.e., one charging pump, one safety injection pump, one RHR pump, one quench spray pump, and two containment recirculation pumps with associated cooler.)
- Failure in the EDG load sequencer or a loss of breaker control power which could prevent one train of containment recirculation pumps from starting and result in two containment recirculation pumps and four ECCS pumps (two charging and two safety injection pumps) running.
- Another partial failure considered is a loss of a MCC which powers the quench spray pump containment isolation valve, the service water inlet valve on each of the containment recirculation system heat exchangers, and the cross-connect valves to the ECCS which are used to establish flow from the containment recirculation pumps to the ECCS pumps during recirculation mode of ECCS

Acceptance Criteria

The containment analysis acceptance criteria are taken from FSAR Table 6.2-3 and are as follows:

- Containment pressure must be less than 45 psig
- Containment liner temperature must be less than 280°F

In addition to the above, the following design limits should also be verified:

- The containment pressure and vapor temperature must be less than the analyzed values for environmentally qualified equipment inside containment.
- The containment sump temperature must be less than the design value for various affected system piping and components of ECCS and containment heat removal systems.

2.6.1.2.2.2 Description of Analyses and Evaluations

The containment pressure and temperature response is analyzed for the primary system breaks that are discussed in Section 2.6.3.1 and FSAR Section 6.2.1.3.

The spectrum of breaks analyzed includes the largest RCS cold and hot leg breaks, and a range of reactor coolant pump suction breaks from the double-ended break with discharge coefficients of 1.0 and 0.6 down to a 3.0 ft^2 split break. The M&E releases for these cases are shown in Tables 2.6.3.1-5 through 2.6.3.1-20. As described above, various single failures of the engineered safety features are analyzed to identify the limiting single failures for each containment acceptance criteria.

There is one pressure peak following a RCS hot leg or cold leg rupture. This pressure peak occurs near the end of the initial blowdown of the RCS after a double-ended guillotine of either a hot or cold leg. This will be referred to as the blowdown peak pressure. Its magnitude is a function of the following parameters:

- The containment free volume. (unchanged by SPU)
- The mass of air inside the containment structure (a function of initial pressure, temperature and humidity).
- The amount of energy flow out of the break during the initial blowdown of the RCS.
- The rate of heat removal from the containment atmosphere by the passive heat sinks within the containment structure. (The passive heat sinks are unchanged by SPU)

A double-ended hot leg guillotine break (DEHL) produces the largest blowdown peak pressure. This event releases the most energy to the containment atmosphere during the initial blowdown since the hot leg pipe size is larger than that of a RCS pump discharge and there is no resistance to flow due to a RCS pump as is the case with a DEPS. The magnitude of the blowdown peak pressure is independent of the active ESF, because the ESF does not become effective until after the peak pressure occurs. However, the accumulators do have a small effect on the blowdown peak pressure.

Following the core reflooding period, the containment heat removal systems and containment passive heat sinks remove energy from the containment atmosphere. As discussed in Section 2.6.3.1.2.1.3, the double-ended pump suction breaks yield the highest energy flow rates during the post-blowdown period and consequently result in the most limiting containment depressurization scenario. The depressurization time is a function of the following parameters:

- The containment free volume. (unchanged by SPU)
- The mass of air inside the containment structure.
- The rate of heat transfer between the containment atmosphere and the passive heat sinks within the containment structure. (The passive heat sinks are unchanged by SPU)
- The rate of heat removal from the containment atmosphere by the containment heat removal systems (this is dependent on the RWST and the ultimate heat sink temperatures).
- The rate of mass and energy release to the containment from the break following the end of core reflooding.
- The mass of nitrogen added to the containment from the SI accumulators.

2.6.1.2.2.2.1 Containment Response Analytical Method

The GOTHIC computer program was developed for the Electric Power Research Institute (EPRI) by Numerical Applications, Inc. It is used to model the containment system, the passive heat sinks, and the containment heat removal systems. A topical report (DOM-NAF-3, Reference 1) described in detail the assumptions used and the mathematical formulations employed. The NRC approved the use of GOTHIC for containment analysis in a letter dated August 30, 2006 (Reference 2). For MPS3, DNC has met the conditions established in the NRC's Safety Evaluation as discussed in Section 2.6.1.2.2. All GOTHIC code and DNC methodology limitations and restrictions (identified in References 1 and 2) have been met.

GOTHIC solves the conservation equations for mass, momentum, and energy for multi-component, multi-phase flow in lumped parameter and/or multi-dimensional geometries. The phase balance equations are coupled by mechanistic models for interface mass, energy, and momentum transfer that cover the entire flow regime from bubbly flow to film/drop flow, as well as single phase flows. The interface models allow for the possibility of thermal non-equilibrium between phases and unequal phase velocities, including countercurrent flow. GOTHIC includes full treatment of the momentum transport terms in multidimensional models, with optional models for turbulent shear and turbulent mass and energy diffusion. Other phenomena include models for commonly available safety equipment, heat transfer to structures, hydrogen burn and isotope transport.

2.6.1.2.2.2.2 Passive Heat Sinks

Thermal conductors are the primary heat sink for the blowdown energy. The conductors can be made up of any number of layers of different materials. One-dimensional conduction solutions are used to be consistent with the lumped modeling approach.

The thermal conductor is divided into regions, one for each material layer, with an appropriate thickness and material property for each region. GOTHIC accepts inputs for material density, thermal conductivity and specific heat. These values are obtained from published literature for the materials present in each conductor. Conductors with high heat flux at the surface and low thermal conductivity must have closely spaced nodes near the surface to adequately track the steep temperature profile. The node spacing is set so the node Biot number for each node is less than 0.1. The Biot number is the ratio of external to internal conductance.

It is not practical or necessary to model each individual piece of equipment or structure in the containment with a separate conductor. Smaller conductors of similar material composition can be combined into a single effective conductor. In this combination, the total mass and the total exposed surface area of the conductors is preserved. The thickness controls the response time for the conductors and is of secondary importance. The conductors are grouped by thickness and material type. The effective thickness for a group of wall conductors is calculated by the equation below. The heat sink material types, surface areas, and thickness are derived based on plant-specific inventories. Concrete, carbon steel, and stainless steel are the most common materials.

$$t_{eff} = \frac{\sum_{i \in group} t_i A_i}{\sum_{i \in group} A_i}$$

Resistance to heat transfer at the liner-concrete interface is considered in the containment analysis by use of a conservatively low value of thermal contact conductance of 100 Btu/hr-ft^2-°F (Gido 1978, Reference 3). Since the steel liner is used as a form for pouring of the concrete, and since the concrete mix is very wet, the liner, in effect, becomes “glued” to the concrete. This contact resistance between the containment liner and the concrete is conservatively modeled in GOTHIC as a separate material layer at the nominal gap thickness with applicable material properties. This overestimates the contact resistance because convection and radiation effects will be ignored. The gap width is determined by dividing the gap thermal conductivity by the gap conductance.

All containment passive heat sinks are included in the lumped containment volume. The primary system metal and SG secondary shells are included in the simplified RCS model that is used for the calculation of long-term mass and energy release; however, these conductors are not used for condensation or convection heat transfer with the containment atmosphere.

2.6.1.2.2.2.3 Conductor Surface Heat Transfer

The Direct heat transfer option with the DLM (Diffusion Layer Model) condensation option is used for all containment passive heat sinks except the sump floor. With the Direct option, all condensate goes directly to the liquid pool at the bottom of the volume. The effects of the condensate film on the heat and mass transfer are incorporated in the formulation of the DLM option. Under the DLM option, the condensation rate is calculated using a heat and mass transfer analogy to account for the presence of non-condensing gases.

For a conductor representing the containment floor or sump walls that will eventually be covered with water from the break and condensate, the Split heat transfer option is used to switch the heat transfer from the vapor phase to the liquid phase as the liquid level in the containment builds. A quicker transition to liquid heat transfer is more conservative for containment analysis. The Split option is used with α_{lmax}, the maximum liquid fraction, set to

$$\alpha_{l_{\max}} = \frac{d}{H}$$

Where d is the transition water depth and H is the volume height. A reasonable value for d of 0.1 inch switches the heat transfer from the vapor phase to the liquid phase as the liquid level in the containment reaches 0.1 inch. Other values may be appropriate depending on the geometry of the floor and sump.

For conductors with both sides exposed to the containment, the Direct option is applied to both sides. Alternatively, if the conductor is symmetric about the centerplane, a half-thickness conductor can be used with the total surface area of the two sides and an insulated back side heat transfer option. The conductor face that is not exposed to the atmosphere is assumed insulated. The Specified Heat Flux option is used with the minimal heat flux set to zero.

Containment walls above grade and the containment dome have a specified external temperature boundary condition with a heat transfer coefficient of 2.0 Btu/hr-ft^2-F to model convective heat transfer to the outside atmosphere. The GOTHIC heat transfer solution scheme allows for accurate initialization of the temperature distribution in the containment wall and dome prior to the transient initiation.

A conservative containment liner response is obtained by adding a small conductor that has the same construction and properties as the liner conductor. A conductor surface area of 1 ft^2 is used to minimize impact on the lumped containment pressure and temperature response. The inside heat transfer option is the same as that used for the actual liner conductor (Direct with DLM) with a multiplier of 1.2 for conservatism.

2.6.1.2.2.2.4 Spray Modeling

GOTHIC includes models that calculate the sensible heat transfer between the drops and the vapor and the evaporation or condensation at the drop surface. The efficiency – the actual temperature rise over the difference between the vapor temperature and the drop inlet temperature – cannot be directly specified in GOTHIC. The efficiency is primarily a function of the drop diameter. The GOTHIC models account for the effect of the diameter through the Reynolds number dependent fall velocity and heat transfer coefficients. A heat and mass transfer analogy is used to calculate the effective mass transfer coefficient, which is used to calculate the evaporation or condensation. Containment spray is modeled as described in DOM-NAF-3-0.0-P-A (Reference 1).

2.6.1.2.2.2.5 Containment Heat Removal

Heat exchangers that remove energy from the containment sump are modeled with the available heat exchanger options in GOTHIC. Use of a GOTHIC heat exchanger option dynamically couples the heat exchanger performance to the predicted primary and secondary fluid conditions. This can provide a small benefit compared to other codes (e.g., LOCTIC) that use bounding UA values to cover the fluid conditions predicted over the entire transient.

The GOTHIC heat exchanger type that closely matches the actual heat exchanger is selected. The inside and outside heat transfer areas are calculated from the heat exchanger geometry details. For tube and shell arrangements, the shell side flow area is set to the open area across the tubes at the mid-plane of the heat exchanger and the shell side hydraulic diameter is set to the tube outer diameter. The GOTHIC option for built-in heat transfer coefficients is used to determine heat transfer coefficients that depend on the primary and secondary side Reynolds and Prandtl numbers. The heat exchanger models in GOTHIC are for basic heat exchanger designs and may not account for the details of a particular heat exchanger (e.g., baffling in a tube-and-shell heat exchanger). A forcing function can be used on the primary and secondary side heat transfer coefficients to tune the heat exchanger performance to manufacturer or measured specifications. Alternatively, the heat transfer area can be adjusted to match the specified performance. Fouling factors and tube plugging are applied when conservative.

2.6.1.2.2.3 Primary Containment Function Design Results

The loss-of-coolant accident (LOCA) containment transient analysis was performed using the GOTHIC computer code (Section 2.6.1.2.2.2.1) for a spectrum of pipe break locations and sizes that are documented in Section 2.6.3.1. The spectrum includes the largest cold and hot leg breaks, and a range of pump suction breaks from the double-ended break with discharge coefficients of 1.0 and 0.6 down to a 3.0 ft^2 split break. These M&E release rates form the basis of GOTHIC computations to evaluate the containment response following the postulated LOCA scenarios and to ensure that containment design margin is maintained.

Peak Pressure Analysis

The results of the containment pressure analysis are tabulated in Table 2.6.1.2.2-1. The initial containment conditions that yield the highest peak calculated containment pressure are the maximum pressure, maximum temperature, and minimum relative humidity, and are provided in Section 2.6.1.2.2.1. The assumption of maximum temperature is different from Table 3.6.1 of DOM-NAF-3-0.0-P-A (Reference 1). As noted in Table 2.6.1.2.2-2 the maximum temperature is only slightly limiting at the minimum relative humidity. At higher relative humidity values, minimum temperature is limiting. The limiting containment pressure transient response for the hot leg, cold leg pump discharge, and cold leg pump suction double-ended ruptures (DERs) are given on Figure 2.6.1.2.2-1 The containment pressure transient response for the three pump suction break sizes analyzed are given on Figure 2.6.1.2.2-2.

The maximum peak containment pressure occurs after a Double Ended Hot Leg. As shown in Table 2.6.1.2.2-1, the calculated containment pressure is below the containment design pressure of 45 psig. The DEHL is the DBA for the containment structure. The sequence of events for the limiting peak pressure case is shown in Table 2.6.1.2.2-3.

A single failure analysis is not necessary for the peak containment pressure evaluation since the peak pressure for each break case analyzed occurs early in the transient before any of the ESF systems start.

Peak Temperature Analysis

The results of the containment temperature analysis are tabulated in Table 2.6.1.2.2-4. The initial containment conditions that yield the highest peak calculated containment temperature are the maximum pressure, temperature, and relative humidity, and are provided in Section 2.6.1.2.2.1. The limiting containment temperature transient response for the spectrum of the LOCA breaks analyzed are given on Figure 2.6.1.2.2-3 and the response for the containment liner temperature is given on Figure 2.6.1.2.2-4.

The maximum peak containment temperature occurs for a Double Ended Hot Leg Break. The results are insensitive to single failures since the peak temperature occurs before the start of any ESF system. The results of this calculation were used to demonstrate that the calculated containment temperature profile is well bounded by the analyzed values for environmentally qualified equipment inside the containment. The sequence of events for the limiting temperature scenario is shown in Table 2.6.1.2.2-5.

Depressurization Analysis

The results of the containment depressurization analysis are tabulated in Table 2.6.1.2.2-6. The initial containment conditions that yield the slowest containment depressurization are the maximum pressure, temperature, and relative humidity, and are provided in Section 2.6.1.2.2.1. The limiting containment pressure transient response for the spectrum of the LOCA breaks analyzed is provided on Figure 2.6.1.2.2-5. From Table 2.6.1.2.2-6 and Figure 2.6.1.2.2-5 the conditions that maximize pressure at one hour are different from the conditions that maximize pressure at five hours.

Only a Double Ended Pump Suction break is considered for the long-term containment depressurization analysis since, as described earlier, this break produces the highest energy flow rates during the post-blowdown period.

The limiting single failure for this analysis was determined to be a diesel generator failure resulting in loss of one ESF train, i.e., one charging pump, one safety injection pump, one RHR pump, one quench spray pump, and two containment recirculation pumps with associated cooler. This single failure has the combined effect of reducing the containment heat removal capability and minimizing the credit for steam condensation due to steam/water mixing, since SI flow is based on a conservative minimum calculation.

The results of this calculation were used to demonstrate that the calculated containment pressure profile is well bounded by the analyzed values for environmentally qualified equipment inside the containment. The sequences of events for the slowest depressurization scenario are shown in Table 2.6.1.2.2-7.

Sump Temperature Analysis

The results of the containment sump temperature analysis are tabulated in Table 2.6.1.2.2-8. The initial containment conditions that yield the highest peak calculated containment sump temperature are the minimum pressure, maximum temperature, and maximum relative humidity, and are provided in Section 2.6.1.2.2.1. The limiting containment sump temperature transient response for the spectrum of the LOCA breaks analyzed are given on Figure 2.6.1.2.2-6.

The maximum containment sump temperature at the start of the containment recirculation pumps occurs after a Double Ended Cold Leg Break at the Pump Discharge. The limiting single failure for this analysis was concluded to be diesel generator failure resulting in the loss of one train of ESF. The result of this analysis was used to verify that the design temperature for various affected system piping and components of ECCS and containment heat removal systems remain bounding. The sequence of events for the limiting sump temperature scenario is shown in Table 2.6.1.2.2-9.

2.6.1.2.3 Main Steam Line Break

The Millstone Unit 3 containment pressure and temperature response to a MSLB was analyzed using the GOTHIC computer code and the NRC-approved analysis methodology described in topical report DOM-NAF-3-0.0-P-A (References 5 and 6). A spectrum of mass and energy release rates is considered that represents a limiting set of break sizes and power levels in order to demonstrate that the containment design pressure and temperature limits will not be exceeded following a steam line rupture inside containment.

The Topical Report and the NRC SER were based on GOTHIC version 7.2. The SPU analysis used GOTHIC version 7.2a, which is functionally identical to version 7.2. Version 7.2a incorporates error corrections identified in GOTHIC version 7.2.

2.6.1.2.3.1 Input Parameters and Assumptions and Acceptance Criteria

Containment initial conditions are biased for conservatism consistent with Table 3.6.1 of DOM-NAF-3-0.0-P-A (Reference 5). The conservative direction of these biases was confirmed for the Millstone 3 MSLB model as follows.

Analysis	Pressure	Temperature	Humidity
MSLB Peak Pressure	MAX	MAX	MIN
MSLB Peak Temperature	MIN	MAX	MIN

The MSLB peak pressure analyses assume an initial containment pressure of 14.2 psia and the MSLB peak temperature analyses assume an initial containment pressure of 10.4 psia. These analysis assumptions include 0.2-psi margin to the Technical Specification 3.6.1.4 operating limits of 10.6-14.0 psia to account for instrument uncertainty. For all MSLB analyses, the initial containment temperature is assumed to be 125°F and the initial relative humidity is assumed to be 0 percent.

For the containment response, one train of emergency power is assumed to be unavailable, leaving one train of the QSS system with minimum flow available for containment cooling. The containment recirculation spray system is not credited in the MSLB containment response analysis. The QSS system is initiated when containment pressure exceeds 24.7 psia and delivers spray to the containment atmosphere 70.2 seconds later. The QSS spray is assumed to be 100°F liquid from the RWST.

No credit is taken for RSS initiation.

The containment analysis acceptance criteria are taken from FSAR Table 6.2-3.

- Containment pressure must be less than 45 psig
- Containment liner temperature must be less than 280°F

In addition, the containment pressure and vapor temperature must be less than the analyzed values for environmentally qualified equipment inside containment.

2.6.1.2.3.2 Description of Analyses

The MSLB containment response is performed using the GOTHIC computer code with the methodology in topical report DOM-NAF-3-0.0-P-A (Reference 5). The containment modeling (geometry, system components, heat structures, and heat transfer options) is consistent with the LOCA model discussed in Section 2.6.1.2.2. The only change from the LOCA model is the modeling of the break effluent. As described in Section 2.6.3.2, the mass and energy releases were developed by Westinghouse for a spectrum of break sizes and power levels (102 percent, 70 percent, 30 percent, and 0 percent power), with and without liquid entrainment, using the LOFTRAN code. The break mass and enthalpy are entered as table forcing functions in GOTHIC. The break junction uses 100-micron droplets for entrained liquid release per

DOM-NAF-3-0.0-P-A, Section 3.5.2 (Reference 5). All GOTHIC and DNC methodology restrictions and limitations were met for the MPS3 MSLB containment analysis.

Sensitivity studies were performed to determine the separate effect impact on the containment pressure and temperature from variations in heat structure surface area, accumulator tank modeling, and RWST temperature. The study results were consistent with the MSLB results in Table 4.7-1 in DOM-NAF-3-0.0-P-A (Reference 5). The GOTHIC MSLB analyses employed the conservative direction of each input parameter.

Table 2.6.1.2.3-1 summarizes the peak containment pressures and temperatures calculated by GOTHIC for 16 combinations of power level and MSLB break size postulated to occur inside containment. The only difference between the peak pressure and peak temperature case at the same statepoint is the initial containment pressure. Thus, the results from 32 GOTHIC analyses are shown in Table 2.6.1.2.3-1.

2.6.1.2.3.3 Primary Containment Function Design Results

2.6.1.2.3.3.1 Containment Peak Pressure

The maximum containment pressure of 38.15 psig (52.85 psia) occurs for the 1.4 ft^2 double-ended rupture at 0 percent power and is less than the design limit of 45 psig. This scenario has the largest initial steam generator liquid mass and results in the largest mass release to the containment. The double-ended rupture cases consistently produce higher peak pressures than the pipe split breaks for the same initial power levels. Containment pressures are also higher when liquid entrainment does not occur, as well as when the MSIV fails to isolate. The results are consistent with expectations since the pressure response is directly related to the quantity of vapor added to containment. Table 2.6.1.2.3-2 shows the time sequence of events for the limiting peak containment pressure case. Figure 2.6.1.2.3-1 shows the containment pressure response from GOTHIC for the same case. Containment pressure decreases at a more rapid rate after 1800 seconds from the termination of auxiliary feedwater, which stops the break release.

The GOTHIC MSLB containment pressure profiles from all 16 cases were confirmed to be less than the analyzed pressures for environmentally qualified equipment in containment.

2.6.1.2.3.3.2 Containment Peak Temperature

The maximum containment temperature of 343.0°F occurs for the 1.4 ft^2 double-ended rupture at 102 percent power. The containment temperature is below the short-term equipment qualification limit of 350°F. Short-term vapor temperatures are considerably higher for the double-ended ruptures without entrainment. A review of the energy release data shows a decrease in the break flow enthalpy early in the event for the entrainment cases. This lower break flow energy significantly reduces the containment temperature response, since containment temperature is directly related to the enthalpy of the fluid in the containment vapor space. The pipe split cases produce peak temperatures that are comparable in magnitude to the double-ended ruptures with entrainment. For the split breaks, the higher enthalpy blowdown flow is delayed with respect to the double-ended ruptures at the same power level. This delay means that there is a lower mass flow rate at the time that the higher energy fluid is being released and that there is more time for the heat structures to remove energy from the containment atmosphere prior to the time of peak temperature. The split break analyses also show that failure of an MSIV to isolate increases the peak temperature by only a few degrees.

As initial power level increases, the containment peak temperature increases. However, this relationship is reversed after several hundred seconds, with marginally higher long-term temperatures for cases initiated at lower power levels because of the larger amount of steam generator liquid mass that is released from the low-power case.

Table 2.6.1.2.3-3 shows the time sequence of events for the limiting peak containment temperature case. Figure 2.6.1.2.3-2 shows the containment temperature response from GOTHIC for the same case.

The GOTHIC MSLB containment temperature profiles from all 16 cases were confirmed to be less than the analyzed temperatures for environmentally qualified equipment in containment.

2.6.1.2.3.3.3 Containment Liner Temperature

The MSLB containment response analyses included an additional 1 ft^2 thermal conductor to determine a conservative containment liner temperature response in accordance with Section 3.3.3 of DOM-NAF-3-0.0-P-A (Table 2.6.1.2.3-1). The conductor used a 1.2 multiplier on the Direct/DLM heat transfer coefficient.

There is little variation in the magnitude of the maximum liner temperature between the cases. In general, the results follow the same trends as the long-term containment temperature response. The double-ended rupture cases without entrainment have marginally higher values than the other cases at the same power levels, and the peak liner temperatures increase slightly at lower initial power level. The maximum calculated liner temperature of 241°F occurs for the 1.4 ft^2 double-ended rupture initiated from 0 percent power. The maximum liner temperature is below the design value of 280°F. Figure 2.6.1.2.3-3 shows the containment liner surface temperature from the limiting case.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The analyses performed to assess the containment response to the limiting LOCA and MSLB resulting from operation at SPU conditions does not add any new components or introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The analytical results associated with operating at SPU conditions do not add any new or previously unevaluated materials to the plant systems. System component internal and external environments remain within the parameters previously evaluated. A review of internal and industry operating experience has not identified the need to modify the basis for Aging Management Programs to account for the effects of SPU. Thus, no new aging effects requiring management are identified.

2.6.1.3 Conclusion

DNC has reviewed the containment pressure and temperature transient and concludes that it adequately accounts for the increase of mass and energy that would result from the proposed SPU. Table 2.6.1.3 compares the current containment analysis results based upon the S&W

LOCTIC methodology to those calculated with the Dominion methodology at SPU conditions. DNC further concludes that containment systems will continue to provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained. The DNC also concludes that the containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and will continue to meet the requirements of GDCs -13, -16, -38, -50, and -64 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to containment functional design.

2.6.1.4 References

1. Dominion Topical Report DOM-NAF-3-0.0-P-A, "GOTHIC Methodology for Analyzing the Response to Postulated Pipe Ruptures Inside Containment," September 2006.

2. NRC Letter "Kewaunee Power Station (Kewaunee), Millstone Power Station, Units Nos. 2 and 3 (Millstone 2 and 3), North Anna Power Station, Unit Nos. 1 and 2 (North Anna 1 and 2) and Surry Power Station, Unit Nos. 1 and 2 (Surry 1 and 2) – Approval of Dominion's Topical Report DOM-NAF-3, "GOTHIC Methodology for Analyzing the Response to Postulated Pipe Ruptures Inside Containment" (TAC Nos. MC8831, MC8832, MC8833, MC8834, MC8835 and MC8836)", dated August 30, 2006

3. Gido, R.G. Liner-Concrete Heat Transfer Study for Nuclear Power Plant Containments, Los Alamos Scientific Laboratory, LA-7089-MS Informal Report NRC-4, issued January 1978.

4. LOCTIC - A Computer Code to Determine the Pressure and Temperature Response of Dry Containments to a Loss-of-Coolant Accident, SWND-1, (SWEC), 1971. Letter from W.J.L. Kennedy to P.A. Morris et al.

5. Dominion Topical Report DOM-NAF-3-0.0-P-A, "GOTHIC Methodology for Analyzing the Response to Postulated Pipe Ruptures Inside Containment," September 2006.

6. NRC Letter "Kewaunee Power Station (Kewaunee), Millstone Power Station, Units Nos. 2 and 3 (Millstone 2 and 3), North Anna Power Station, Unit Nos. 1 and 2 (North Anna 1 and 2) and Surry Power Station, Unit Nos. 1 and 2 (Surry 1 and 2) – Approval of Dominion's Topical Report DOM-NAF-3, "GOTHIC Methodology for Analyzing the Response to Postulated Pipe Ruptures Inside Containment" (TAC Nos. MC8831, MC8832, MC8833, MC8834, MC8835 and MC8836)", dated August 30, 2006

Table 2.6.1.2.2-1
Peak Pressure Results

Break Location	Peak Pressure (psia)	Time of Peak Pressure (sec)
DE Hot Leg	56.09	21.2
DE Pump Suction	54.29	21.5
DE Pump Suction 0.6 CD	52.31	22.7
Pump Suction (3 ft^2)	51.29	32.6
DE Pump Discharge	47.69	16.7

Table 2.6.1.2.2-2
Peak Pressure - DEHL Break - Initial Conditions

Initial Pres. (psia)	Initial Temp (F)	Initial RH (%)	Peak Press (psia)
14.2	125	0	56.09
14.2	75	0	56.03
14.2	125	50	55.57
14.2	75	50	55.86
14.2	125	100	55.15
14.2	75	100	55.81

Table 2.6.1.2.2-3
LOCA Sequence of Events - Containment Peak Pressure

Event	Time (sec)
Accident begins	0.0
CDA set point reached (10 psig)	1.9
Containment peak pressure occurs (56.09 psia)	21.2
End of Blowdown	23.2

Table 2.6.1.2.2-4
Peak Temperature Results

Break Location	Peak Temperature (F)	Time of Peak Temperature
DE Hot Leg	267.1	21.1
DE Pump Suction	263.4	21.1
DE Pump Suction 0.6 CD	262.8	22.5
Pump Suction (3 ft^2)	259.4	32.3
DE Pump Discharge	262.9	16.7

Table 2.6.1.2.2-5
LOCA Sequence of Events - Containment Peak Temperature

Event	Time (sec)
Accident begins	0.0
CDA set point reached (10 psig)	1.9
Containment peak temperature occurs (267.1 F)	21.1
End of Blowdown	23.2

Table 2.6.1.2.2-6
Containment Depressurization Results - DEPS Break

Initial Pressure (psia)	Initial Temperature (F)	Initial Relative Humidity (%)	Single Failure	Pressure at 1 hr (psia)	Pressure at 5 hrs (psia)
14.2	75	0	1 EDG	28.5	22.6
14.2	125	0	1 EDG	30.2	22.1
14.2	75	50	1 EDG	28.4	22.3
10.4	125	50	1 EDG	25.0	16.9
14.2	75	0	MCC	22.4	22.5

Table 2.6.1.2.2-7
LOCA Sequence of Events - Containment Depressurization

Event	Time (sec)
Accident begins	0.0
Containment peak pressure occurs (54.28 psia)	21.1
End of Blowdown	26.0
Safety Injection becomes effective	45.4
Quench Spray becomes effective	71.9
Recirculation spray become effective	5128
Switchover to Recirculation Mode	5875
Quench spray terminates	10717
Maximum post-Quench Spray peak pressure occurs (23.2 psia)	12630

Table 2.6.1.2.2-8
Containment Sump Water Temperature At RSS Pump Start

Break Type	Single Active Failure	Initial Pressure (psia)	Initial Temperature (F)	Sump Temp at RSS Start (F)
Double Ended Pump Discharge	1EDG	10.4	125	221.6
Double Ended Pump Suction	1EDG	14.2	125	217.4
Double Ended Hot Leg	1EDG	14.2	125	209.4
Pump Suction-Discharge Coefficient 0.6	1EDG	14.2	125	208.5
Pump Suction-3 sq. ft.	1EDG	14.2	125	208.2
Cold Leg Slot Break-8 in	1EDG	14.2	125	199.7
Hot Leg Slot Break -8in	1EDG	14.2	125	190.9

Table 2.6.1.2.2-9
Accident Chronology for Pump Discharge Double Ended Rupture – Limiting Case for Containment Sump Temperature

Event	Time (sec)
Accident begins	0.0
Containment peak pressure occurs	16.61
End of Blowdown	22.4
Nitrogen Accumulator Injects	43.99
Safety Injection actuates	45.3
Quench spray actuates	72.7
RHS Auto setpoint actuates	4198.4
RSS pump flow begins	4356
Switchover to Recirculation completed	5098.4
Quench spray terminates	10,970

Table 2.6.1.2.3-1
Containment Peak Pressure and Temperature Results Following a Main Steam Line Break Inside Containment

Power Level (%)	Break Size (ft^2)	Break Type	Mass/Energy Assumed Failure[1]	Entrainment[2]	Pressure[3]		Temperature[4]	
					Peak (psia)	Time (sec)	Peak (°F)	Time (sec)
102	1.4	DER	MSIV	No	47.58	150.3	343.0	12.8
102	1.4	DER	MSIV	Yes	45.59	126.2	250.3	120.2
102	0.653	Split		No	40.19	290.2	245.0	67.1
102	0.653	Split	MSIV	No	42.02	314.3	245.0	67.7
70	1.4	DER	MSIV	No	48.2	178.3	341.3	12.8
70	1.4	DER	MSIV	Yes	45.54	148.3	248.6	142.3
70	0.659	Split		No	40.56	332.3	245.0	62.3
70	0.659	Split	MSIV	No	42.51	358.3	247.9	274.4
30	1.4	DER	MSIV	No	48.77	158.2	339.8	12.6
30	1.4	DER	MSIV	Yes	45.01	115.1	246.4	113.1
30	0.671	Split		No	42.21	282.2	248.5	276.5
30	0.671	Split	MSIV	No	44.24	310.3	252.7	302.5
0	1.4	DER	MSIV	No	52.85	194.3	338.1	12.6
0	1.4	DER	MSIV	Yes	47.56	140.2	253.1	138.3
0	0.512	Split		No	44.92	412.4	253.4	406.4

Table 2.6.1.2.3-1
Containment Peak Pressure and Temperature Results Following a Main Steam Line Break Inside Containment

Power Level (%)	Break Size (ft^2)	Break Type	Mass/Energy Assumed Failure[1]	Entrainment[2]	Pressure[3]		Temperature[4]	
					Peak (psia)	Time (sec)	Peak (°F)	Time (sec)
0	0.512	Split	MSIV	No	46.95	444.4	257.2	438.5

1. All cases assume a MFIV failure. This column identifies whether the mass and energy release analysis also assumed an MSIV failure. The GOTHIC containment analyses assume the failure of an emergency bus to minimize containment cooling.
2. Identified cases with entrainment in the faulted loop steam generator assess the effect of this assumption.
3. Cases assume maximum initial containment pressure of 14.2 psia to maximize containment pressure.
4. Cases assume minimum initial containment pressure of 10.4 psia to maximize containment temperature.

Table 2.6.1.2.3-2
Accident Chronology for Full Double-Ended Rupture Main Steam Line Break at 0% Power – Limiting Case for Containment Pressure

Time (sec)	Event
0.0	Accident occurs, ruptured steam generator and turbine plant piping blowdown into containment begins
0.47	Steam Line Isolation setpoint for closing the MSIV and FWIV is reached
4.0	Containment pressure setpoint for spray initiation is reached
7.47	FWIV is fully closed
12.47	MSIV is fully closed
74.24	Quench spray enters containment atmosphere
194.3	Peak containment pressure is reached
1800.0	AFW is isolated by operator action
1801.6	Steam release to containment ends

Table 2.6.1.2.3-3
Accident Chronology for Full Double-Ended Rupture Main Steam Line Break at 102% Power – Limiting Case for Containment Temperature

Time (sec)	Event
0.0	Accident occurs, ruptured steam generator and turbine plant piping blowdown into containment begins
0.73	Steam Line Isolation setpoint for closing the MSIV and FWIV is reached
6.06	Containment pressure setpoint for spray initiation is reached
7.73	FWIV is fully closed
12.73	MSIV is fully closed
12.81	Peak containment temperature is reached
76.34	Quench spray enters containment atmosphere
1800.0	AFW is isolated by operator action
1802.0	Steam release to containment ends

Table 2.6.1.3
Comparison of Current and SPU Results

	Current	SPU	Limit
LOCA Peak Pressure, psig	38.28	41.4 (56.09 psia)	45
Steam Line Break Peak Pressure, psig	34.14	38.15	45
Steam Line Break Peak Temperature, degrees F	335.9	343	350[1]
1. Current maximum temperature from EEQ profile			

Figure 2.6.1.2.2-1
Containment Pressure Response - LOCA (Break Location)

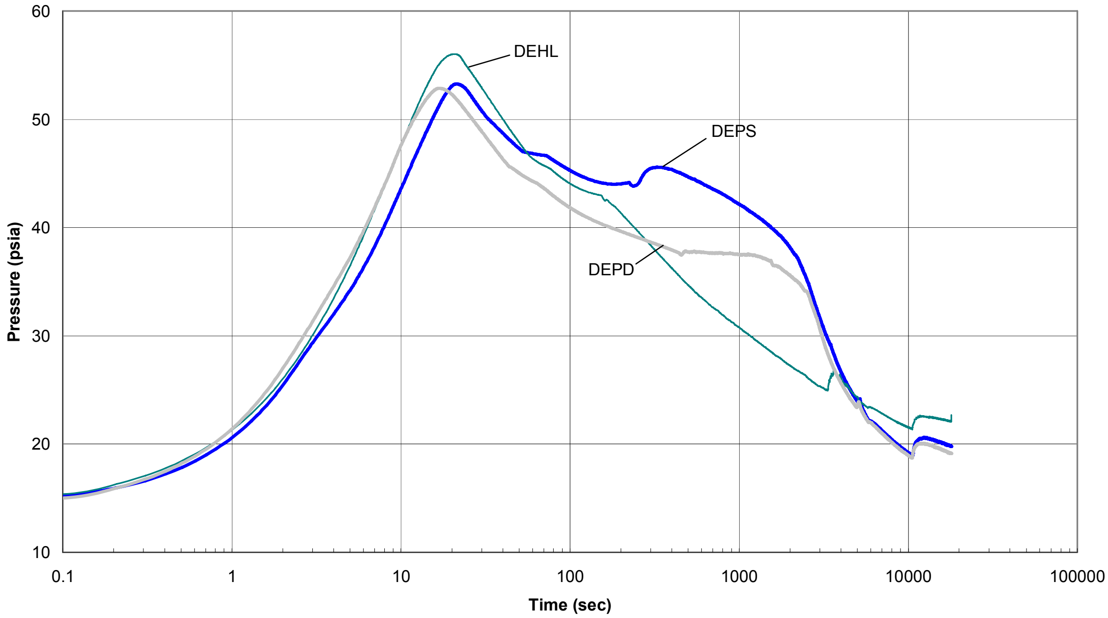


Figure 2.6.1.2.2-2
Containment Pressure Response - LOCA (Break Size)

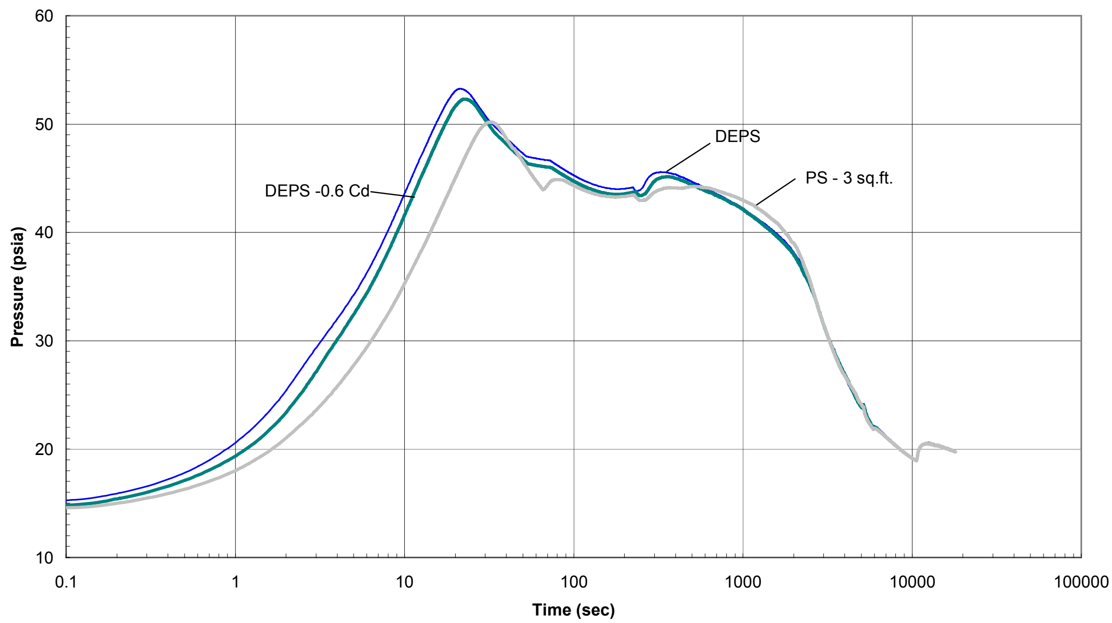


Figure 2.6.1.2.2-3
Containment Vapor Temperature Response - LOCA

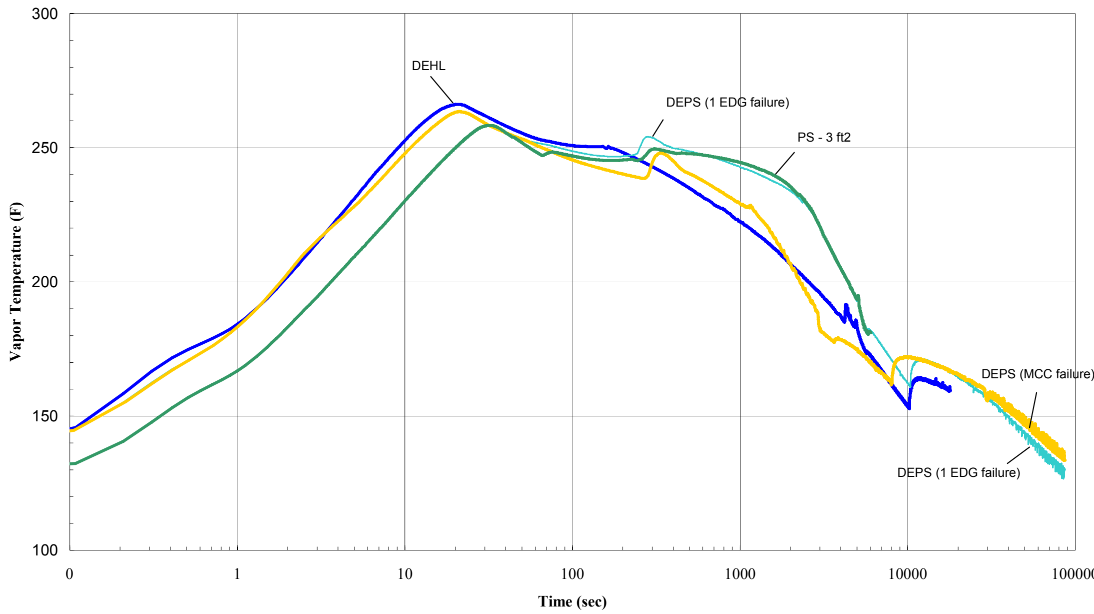


Figure 2.6.1.2.2-4
Containment Liner Temperature Response - LOCA

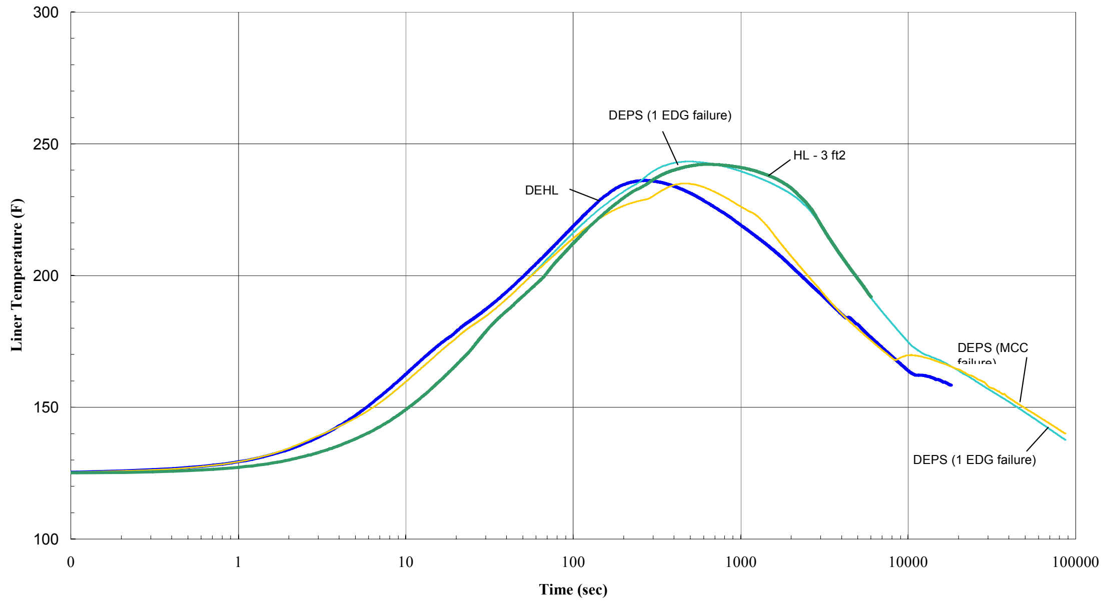


Figure 2.6.1.2.2-5
Containment Depressurization Response – LOCA

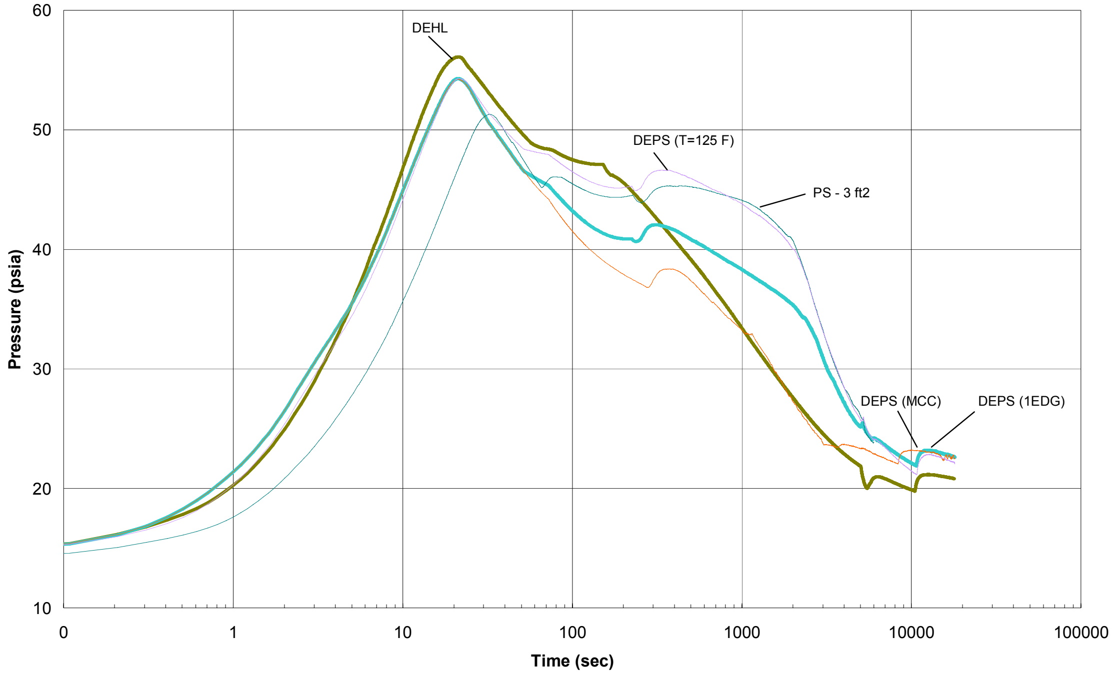


Figure 2.6.1.2.2-6
Containment Sump Temperature Response

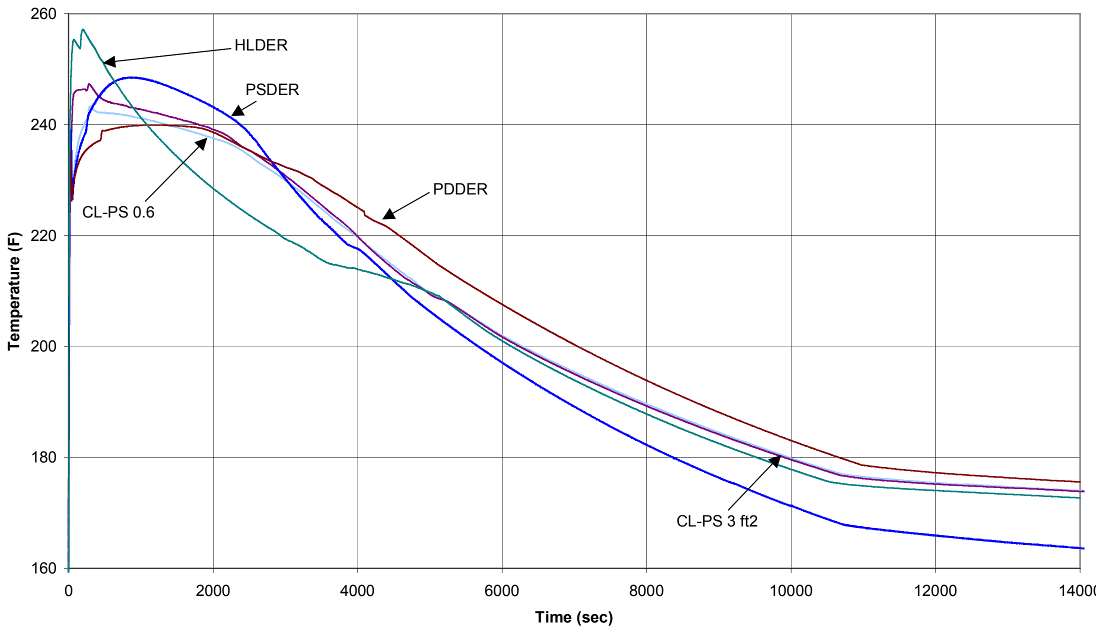


Figure 2.6.1.2.3-1
Containment Pressure from 1.4 ft^2 MSLB at 0% Power, No Entrainment – Limiting Peak Pressure Case

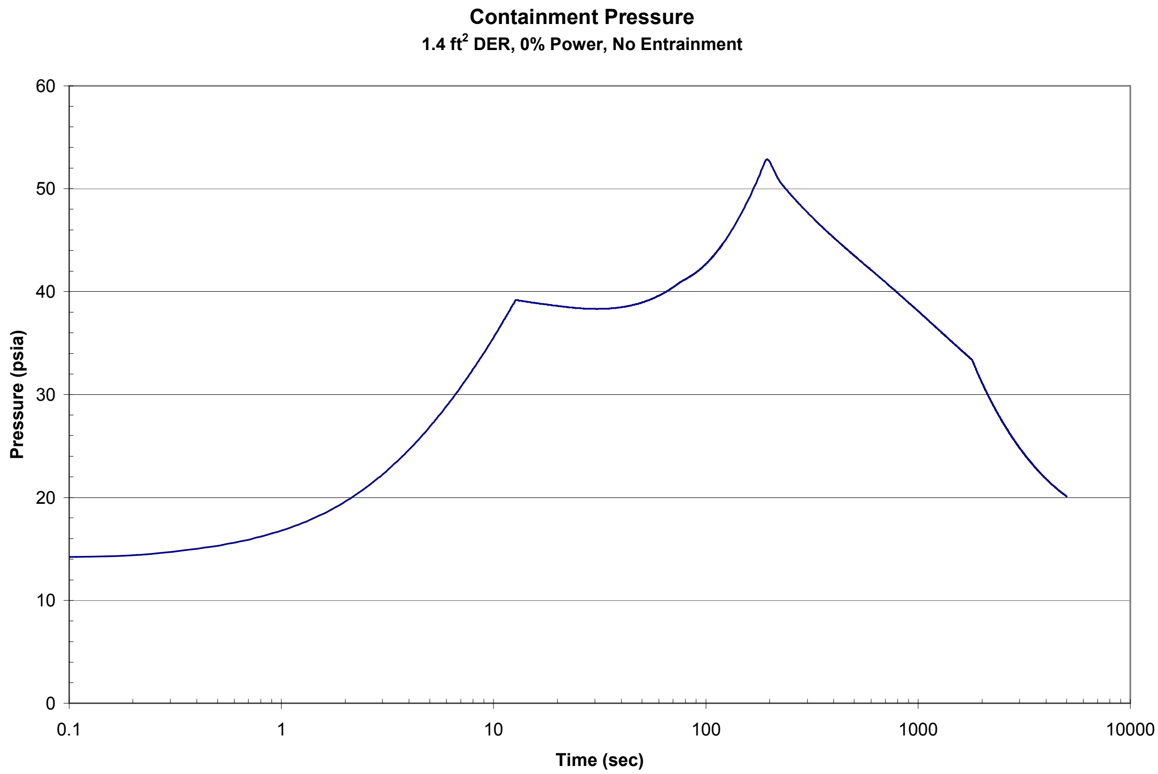


Figure 2.6.1.2.3-2
Containment Temperature from 1.4 ft^2 MSLB at 102% Power, No Entrainment – Limiting Peak Temperature Case

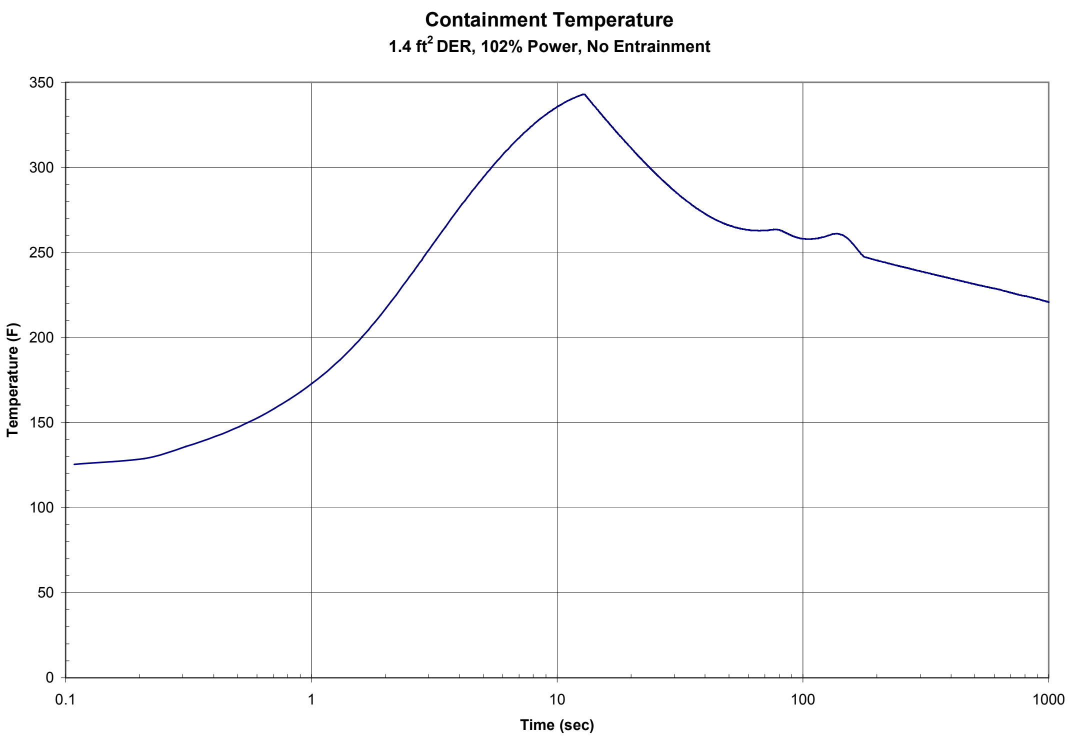
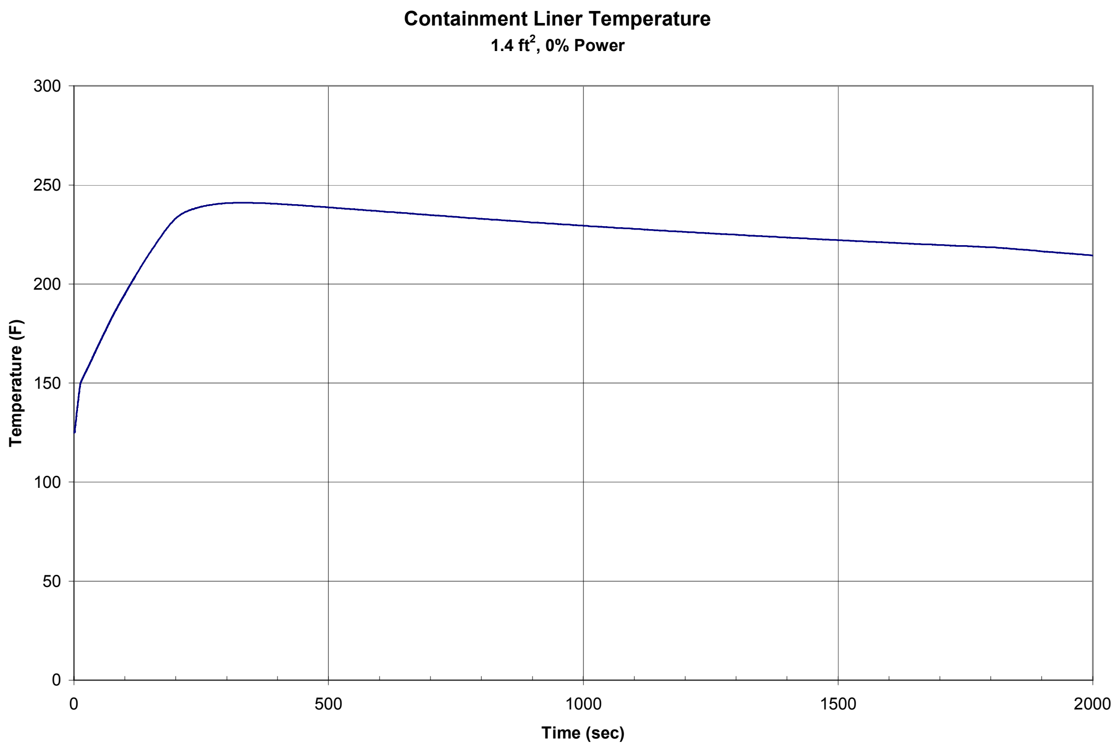


Figure 2.6.1.2.3-3
Containment Liner Temperature from 1.4 ft^2 MSLB at 0% Power, No Entrainment – Peak Temperature Case



2.6.2 Subcompartment Analyses

2.6.2.1 Regulatory Evaluation

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The DNC review for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The review focused on the effects of the increase in mass and energy release into the containment due to operation at SPU conditions and the resulting increase in pressurization.

The acceptance criteria for subcompartment analyses are based on:

- GDC-4, insofar as it requires that structures, systems, and components (SSCs) important-to-safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects, and
- GDC-50, insofar as it requires that the containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments.

Specific review criteria are contained in SRP Section 6.2.1.2, and guidance is provided in Matrix 6 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), Section 6.2.1.2, Rev. 2.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to conformance to:

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4)

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCA’s. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  In a letter from B. J. Youngblood (NRC) to J. F. Opeka (NNECO) dated June 5, 1985, Millstone 3 was granted an exemption for a period of two cycles of operation from those portions of General Design Criterion 4 which require protection of structures, systems, and components from the dynamic effects associated with postulated breaks in the reactor coolant system primary loop piping.

In Federal Register, Volume 51, No. 70, dated April 11, 1986, the NRC published a final rule modifying General Design Criterion 4 to allow use of leak-before-break technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in pressurized water reactors. This rule obviates the need for the above exemption.

Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-50 is described in FSAR Section 3.1.2.50, Containment Design Basis (Criterion 50)

  The containment structure is designed with a leakage rate shown in Table 1.3-3. The containment is designed to withstand, by a sufficient margin, loads above those that are conservatively calculated to result from a DBA as discussed in Section 6.2.1.

Additional details that define the licensing basis for the subcompartment analyses are defined in FSAR Section 6.2.1.2.

In addition to the commitments described above, the subcompartment analyses were reviewed for continued acceptability to support plant license renewal at SPU conditions. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005 documents the results of that review. Post-LOCA subcompartment analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.6.2.2 Technical Evaluation

2.6.2.2.1 Introduction

The containment subcompartments were evaluated for their structural response to potential increases in pressure differentials resulting from postulated accidents that are conservatively assumed to initiate at SPU operating conditions. The pressure transient, resulting from postulated accidents, produces a pressure differential across the walls of the subcompartment, which reaches a maximum value generally within the initial few seconds after blowdown begins.

2.6.2.2.2 Description of Analyses and Evaluations

The SPU analyses were performed using the current licensing basis methodology documented in FSAR Section 6.2.1.2, Containment Subcompartments.

The uncontrolled release of pressurized high-temperature reactor coolant, termed a LOCA, will result in the release of steam and water into the containment. Short-term effects on the containment subcompartments resulting from a postulated LOCA were considered using the condition for MPS3 at the SPU core power. For containment subcompartment analysis, the short-term LOCA RCS mass and energy release rates are discussed in Section 2.6.3.1.2.2, Short-Term LOCA M&E Releases.

As noted in Section 2.6.3.1.2.2, MPS3 is approved for LBB methods for the large RCS line breaks.

As discussed in Section 2.6.3.1.2.2, the application of LBB methodology for large RCS pipe breaks within the containment subcompartments results in no further need to evaluate the following pipe ruptures for SPU:

- SG Inlet Nozzle with 196.6 in^2 Limited Displacement Rupture (LDR)
- RCS Hot Leg Intrados Split Break with 707 in^2 Opening
- SG Outlet Nozzle with 500 in^2 LDR
- Pump Suction Loop Closure Weld 500 in^2 LDR
- RCS Cold Leg 100 in^2 LDR

The RHR line break inside the steam generator cubicle has a single ended break area of 86.59 in^2. The referenced break is currently analyzed using the LOCA M&E associated with the 196.6 in^2 pressurizer surge line break. The RHR break area is 44 percent the area of the pressurizer surge line break; therefore, for SPU, the RHR break has a much lower LOCA short-term M&E release and is bounded by current analysis. No further evaluation of RHR break within the steam generator cubicle is needed for the SPU.

The short-term M&E within the steam generator cubicle for the SPU associated with the 238.8 in^2 Single Ended Split (SES) feedwater line break, is generated using the Moody critical flow model based on a flow resistance value of f L/D = 1.0. The pre-SPU analysis was conservatively based on a frictionless Moody critical flow model and bounds the SPU condition.

As noted in Section 2.6.3.1.2.2, the LOCA short-term M&E associated with the pressurizer spray line break and the pressurizer surge line break has increased for the SPU.

For the spray line break, the SPU LOCA short-term M&E increase is within the 10 percent margin included in the current evaluations and documented in FSAR Table 6.2-31. Consequently, no further evaluation of spray line break within the pressurizer cubicle is needed for the SPU.

The LOCA short-term M&E associated with the pressurizer surge line break has increased by as much 15.75 percent on mass released and 11.27 percent on energy released. Taking into consideration the 10 percent margin currently included in the existing evaluations and documented in FSAR Table 6.2-32A, the SPU subcompartment analysis addressed the impact of an increase in M&E of 5.23 percent and 1.15 percent, respectively.

The pressurizer surge line break impacts the subcompartment analyses for both the pressurizer and the steam generator cubicles. Subcompartment pressurization calculations are performed to support analysis of the concrete structures surrounding the steam generators (FSAR Section 6.2.1.2) and the concrete structure surrounding the pressurizer (FSAR Section 6.2.1.2). The analyses are performed to ensure that the walls and platforms of a subcompartment will maintain their structural integrity during the short pressure pulse accompanying a high-energy line pipe rupture within that subcompartment at SPU conditions. The SPU evaluation utilizes current licensing basis methodology, computer code and compartment nodalizations as discussed in FSAR Section 6.2.1.2.

2.6.2.3 Results

It has been determined that the current short-term M&E utilized for the feedwater line break within the steam generator cubicle bounds the SPU conditions by utilizing the Moody critical flow model and applying a flow resistance of 1.0.

The increase in the pressurizer surge line SPU LOCA short-term M&E will cause an increase of pressure differential across the pressurizer cubicle walls of 2 percent and an increase across the pressurizer support platform of 11 percent. The design of the pressurizer cubicle has been evaluated for this pressure increase and determined to be acceptable. Analysis of the pressurizer cubicle walls has demonstrated that the current design pressure for the limiting wall element remains bounding with no net decrease in the design basis margin (i.e. the margin between the current design pressure utilized in the structural analysis and the allowable design pressure associated with the limiting wall element). Effects on piping and components within the pressurizer cubicle are addressed in Section 2.2.2.1, NSSS Piping, Components and Supports (Class 1).

The increase in the pressurizer surge line SPU LOCA short-term M&E will cause an increase of pressure differentials in the steam generator cubicle of approximately 5 percent for the pressurizer surge line break case. The increased differential pressure across the subcompartment walls is bounded by the current analysis results for the steam generator compartment. Effects on piping and components within the Steam Generator cubicle are addressed in Section 2.2.2.1, NSSS Piping, Components and Supports (Class 1).

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Containment subcompartment analyses considerations were evaluated for plant License Renewal. No systems or components are being added or modified as the result of re-evaluation of subcompartment analyses described in this section involve only analytical techniques and results that do not introduce new functions for existing components that would change the license renewal boundaries. Therefore, no new aging effects requiring management are identified with respect to containment subcompartment analyses.

2.6.2.4 Conclusion

DNC has reviewed the subcompartment assessment and the change in predicted pressurization resulting from the increased mass and energy release. DNC concludes that containment SSCs important to safety will continue to be protected from the dynamic effects resulting from pipe breaks and that the subcompartments will continue to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed SPU. Based on this, DNC concludes that the plant will continue to meet the MPS3 current licensing basis with respect to the requirement of GDCs 4 and 50 for the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to subcompartment analysis.

2.6.3 Mass and Energy Release

2.6.3.1 Mass and Energy Release Analysis for Postulated Loss of Coolant

2.6.3.1.1 Regulatory Evaluation

The release of high-energy fluid from pipe breaks could challenge the structural integrity of the containment, including subcompartments and systems within the containment. DNC's review covered the energy sources that are available for release to the containment and the Mass and Energy (M&E) release rate calculations for the initial blowdown phase of the accident.

The acceptance criteria for M&E release analyses for postulated LOCAs are based on:

- GDC-50, insofar as it requires that sufficient conservatism is provided in the M&E release analysis to assure that containment design margin is maintained
- 10 CFR 50, Appendix K, insofar as it identifies sources of energy during a LOCA

Specific review criteria are contained in SRP Sections 6.2.1 and 6.2.1.3, and guidance provided in Matrix 6 of RS-001.

MPS3 Current Licensing Basis

As noted in the FSAR Section 3.1, the MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Sections 6.2.1 and 6.2.1.3, Revs. 2 and 1, respectively.

As noted in the FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of assumptions regarding energy sources available for release to the containment and the M&E release rate calculations relative to conformance to:

- GDC-50, Containment Design Basis, is described in FSAR Section 3.1.2.50:

  The containment structure is designed with a leakage rate shown in FSAR Table 1.3-3. The containment is designed to withstand, by a sufficient margin, loads above those that are conservatively calculated to result from a DBA as discussed in FSAR Section 6.2.1.

  For purposes of evaluating the integrity of the containment as a whole and the integrity of structures internal to the containment (subcompartments), the effects of M&E releases are examined for both long and short term releases, respectively.

  Section 2.6.1 addresses the primary containment functional design. It discusses the containment LOCA response analysis. In addition, the containment functional design requirements are discussed in FSAR Section 6.2.1.1.1.

FSAR Section 6.2.1.3 provides the current licensing basis analysis regarding M&E releases to the containment subsequent to a LOCA. This analysis identifies the sources of energy available for release to the containment.

Section 2.6.2 discusses the containment subcompartment analysis in more detail. FSAR Section 6.2.1.2 provides a discussion regarding the short term M&E release calculations impact on containment subcompartments. FSAR Section 6.2.1.2.1 identifies the following breaks as the bounding breaks:

- Upper pressurizer cubicle – Double-ended rupture (DER) of a pressurizer spray line
- Lower pressurizer cubicle – DER of a pressurizer surge line, even though the largest break that can occur within this area is a limited displacement rupture of less than two pipe cross-section areas of a pressurizer surge line
- Lower steam generator subcompartments – RCS 707 in^2 hot leg intrados split break
- Upper steam generator subcompartments – Feedwater line single-ended split.
- Upper reactor cavity – RCS 100 in^2 cold leg limited displacement break, even though this break area exceeds the maximum that can occur inside the upper reactor cavity

NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3," dated August 1, 2005 defines the scope of license renewal. The M&E release transients are not within the scope of license renewal.

2.6.3.1.2 Technical Evaluation

2.6.3.1.2.1 Long-Term LOCA M&E Releases

The evaluation/generation of the design basis long-term LOCA M&E release data was completed to support the SPU operation.

2.6.3.1.2.1.1 Introduction

The long-term LOCA M&E releases are described in the FSAR Section 6.2.1.3. The M&E release rates described in this section form the basis of further computations to evaluate the containment response following the postulated LOCA (FSAR Section 6.2.1.1) and to ensure that containment design margin is maintained.

The uncontrolled release of pressurized high-temperature reactor coolant, termed a LOCA, will result in the release of steam and water into the containment. This, in turn, will result in increases in the local subcompartment pressures and an increase in the global containment pressure and temperature. Therefore, both long-term and short-term effects on the containment resulting from a postulated LOCA were considered using the conditions for MPS3 at the SPU uprated core power.

The long-term LOCA M&E releases analyzed using the References 1and 2 methodologies for the MPS3 SPU program were analyzed out to end of reflood. The long-term post reflood releases were calculated by the GOTHIC code and were utilized with the blowdown and reflood transient releases from the Reference 1 and 2 methods in the containment integrity analysis (discussed in Section 2.6.1). To demonstrate the acceptability of the containment safeguards systems to mitigate the consequences of a hypothetical large-break LOCA (LBLOCA), the long-term LOCA M&E releases were generated by the GOTHIC code for containment integrity analysis. The containment safeguards systems must be capable of limiting the peak containment pressure to less than the design pressure, and limiting the temperature excursion to less than the EQ acceptance limits.

The SPU analyses were performed using the Westinghouse LOCA M&E Release Model for Containment Design March 1979 Version, described in WCAP-10325-P-A (Reference 1) and WCAP-8264-P-A, "Topical Report Westinghouse Mass and Energy Release Data For Containment Design" (Reference 2). The NRC review and approval letter is included with References 1 and 2. Section 2.6.3.1.2.1, Long-Term LOCA M&E Releases, discusses the long-term LOCA M&E releases generated for the SPU program.

The short-term LOCA-related M&E releases were used as input to the subcompartment analyses (see Section 2.6.2, Subcompartment Analyses). These analyses were performed to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse (generally less than 2 seconds) accompanying a high-energy line pipe rupture within that subcompartment. Short-term M&E release calculations are performed to support reactor coolant loop (RCL) compartments (FSAR Section 6.2.1.3.2), the concrete around and under the reactor vessel (FSAR Section 6.2.1.3.4), and the concrete structures around the steam generator (FSAR Section 6.2.1.3.4). Since MPS3 is approved for LBB, the LBB methodology was used to qualitatively demonstrate that any changes associated with the SPU are offset by the LBB benefit (i.e., the use of smaller RCS nozzle breaks). However, the smaller breaks used for the pressurizer compartments and steam generator compartments required a separate evaluation. The critical mass flux correlation utilized in the SATAN computer program (Reference 2) was used to conservatively estimate the impact of the changes in RCS temperatures on the short-term release. The evaluation showed that the design basis releases would remain bounding for all breaks, except the pressurizer surge line break which showed modest increases. Section 2.6.3.1.2.2, Short-Term LOCA M&E Releases, discusses the short-term LOCA M&E releases generated for the SPU program. Section 2.6.2, Subcompartment Analyses, discusses the short-term evaluation conducted for this program.

2.6.3.1.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are utilized and instrumentation uncertainties are included. For example, the RCS operating temperatures were chosen to bound the highest average coolant temperature range of all operating cases, and a temperature uncertainty allowance was then added (+4°F with a 1ºF bias for a total of 5.0ºF). The RCS pressure in this analysis is based on a nominal value of 2250 psia, plus an uncertainty allowance (+50 psi). Nominal parameters are used in certain instances. All input parameters are chosen consistent with accepted analysis methodology.

Some of the most critical items are the RCS initial conditions, core decay heat, safety injection flow, and primary and secondary metal mass and steam generator heat release modeling. Specific assumptions concerning each of these items are discussed in the following paragraphs. Tables 2.6.3.1-1 through 2.6.3.1-3 present key data assumed in the analysis.

The core-rated power of 3723 MWt, adjusted for calorimetric error (i.e., 102 percent of 3650 MWt), was used in the analysis. As previously noted, the use of RCS operating temperatures to bound the highest average coolant temperature range were used as bounding conditions. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures, which are at the maximum levels attained in steady-state operation. Additionally, an allowance to account for instrument error and dead band was reflected in the initial RCS temperature. As previously discussed, the initial RCS pressure in this analysis was based on a nominal value of 2250 psia, plus an allowance that accounted for the measurement uncertainty on pressurizer pressure. The selection of 2300 psia as the limiting pressure is considered to affect blowdown phase results only, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value until the point where it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure. Additionally, the RCS has a higher fluid density at the higher pressure (assuming a constant temperature), and subsequently has a higher RCS mass available for releases. Thus, 2250 psia plus uncertainty was selected for the initial pressure as the limiting condition for the long-term M&E release calculations.

The selection of the fuel design features for the long-term M&E release calculation is based on the need to conservatively maximize the energy stored in the fuel at the beginning of the postulated accident (that is, to maximize the core-stored energy). The core-stored energy that was selected for the 17x17 RFA-2 fuel product bounds the core-stored energy for all 17X17 fuel products and cores with a mixture of different fuel products. The core-stored energy is based on the time in life for maximum fuel densification. The assumptions used to calculate the fuel temperatures for the core-stored energy calculations account for appropriate uncertainties associated with the models in the PAD code (such as calibration of the thermal model, pellet densification model, or clad creep model). In addition, the fuel temperatures for the core-stored energy calculation account for appropriate uncertainties associated with manufacturing tolerances (such as pellet as-built density). The total uncertainty for fuel temperature calculation is a statistical combination of these effects and is dependent upon fuel type, power level, and burnup. Thus, the analysis very conservatively accounts for the stored energy in the core.

The RCS volume is increased by 3 percent, which is composed of a 1.6 percent allowance for thermal expansion and a 1.4 percent allowance for uncertainty.

A uniform steam generator tube plugging (SGTP) level of 0 percent was modeled. This assumption maximized the reactor coolant volume and fluid release by including the RCS fluid in all steam generator tubes. During the post-blowdown period, the steam generators are active heat sources since significant energy remains in the secondary metal and secondary mass that has the potential to be transferred to the primary side. The 0 percent tube plugging assumption maximized heat transfer area and, therefore, the transfer of secondary heat across the steam generator tube. Additionally, this assumption reduced the RCL resistance, which reduced the ΔP

upstream of the break for the pump suction breaks and increased break flow. Thus, the analysis very conservatively modeled the effects related to SGTP.

The secondary-to-primary heat transfer is maximized by assuming conservative heat transfer coefficients. This conservative energy transfer is ensured by maximizing the initial internal energy of the inventory in the steam generator secondary side. This internal energy is based on full-power operation plus uncertainties.

Following a large break LOCA inside containment, the safety injection system (SIS) operates to reflood the RCS. The first phase of the SIS operation is the passive accumulator injection. Four accumulators are assumed available to inject. When the RCS depressurizes below 664.7 psia the accumulators begin to inject. The accumulator injection temperature was conservatively modeled high at 120°F. Relative to the active pumped emergency core cooling system (ECCS) operation, the M&E release calculation considered configurations, component failures, and offsite power assumptions to conservatively bound respective alignments. The cases include a minimum safeguards case (one charging/SI [Chrg/SI] pump, one high-head SI [HHSI] pump, and one low-head SI [LHSI] pump, see Table 2.6.3.1-2), and a maximum safeguards case, [two Chrg/SI, two HHSI and two LHSI pumps, see Table 2.6.3.1-3]. In addition, a conservative containment backpressure was assumed to bound the GOTHIC calculated results. The assumption of high containment backpressure was shown in Reference 1 to be conservative for the generation of M&E energy releases.

In summary, the following assumptions were employed to ensure that the M&E releases are conservatively calculated, thereby maximizing energy release to containment:

- Maximum expected operating temperature of the RCS (100 percent full-power operation)
- Allowance for RCS temperature uncertainty (+5.0°F which includes a 1ºF bias)
- Margin in RCS volume of 3 percent (which is composed of 1.6-percent allowance for thermal expansion, and 1.4 percent allowance for uncertainty)
- Core rated power of 3650 MWt
- Allowance for calorimetric error (2.0 percent of power)
- Conservative heat transfer coefficients (i.e., steam generator primary/secondary heat transfer and RCS metal heat transfer)
- Allowance in core-stored energy for effect of fuel densification
- An allowance for RCS initial pressure uncertainty (+50 psi)
- A total uncertainty for fuel temperature calculation based on a statistical combination of effects and dependent upon fuel type, power level, and burnup
- A maximum containment backpressure from the containment analysis.
- SGTP level (0 percent uniform)
  - Maximizes reactor coolant volume and fluid release
  - Maximizes heat transfer area across the steam generator tubes

- • Reduces RCL resistance, which reduces the ΔP upstream of the break for the pump suction breaks and increases break flow

Thus, based on the previously discussed conditions and assumptions, an analysis of the MPS3 was performed for the release of M&E from the RCS in the event of LOCA at 3650 MWt core power.

Application of Single-Failure Criterion

An analysis of the effects of the single-failure criterion has been performed on the M&E release rates for each break analyzed. An inherent assumption in the generation of the M&E release is that offsite power is lost with the pipe rupture. This results in the actuation of the emergency diesel generators (EDGs), required to power the safety injection system. Operating the EDG delays the operation of the SIS that is required to mitigate the transient. This is not an issue for the double-ended hot leg break (DEHL) which is blowdown limited.

Two cases were analyzed to assess the effects of a single failure. The first case assumed minimum safeguards SI flow based on the postulated single failure of an EDG. This assumption results in the loss of one train of safeguards equipment. Thus the remaining ECCS was conservatively modeled as: one Chrg/SI pump, one HHSI pump and one LHSI pump. The other case assumed maximum safeguards SI flow based on no postulated failures that could impact the amount of ECCS flow. The maximum safeguards case was modeled as: two Chrg/SI pumps, two HHSI pumps and two LHSI pumps. The single failure assumption postulated is the failure associated with containment heat removal systems. However, this has no impact on the amount of ECCS flow and, therefore, no impact on the M&E release portion of the analysis during the RWST injection phase of the transient. The analysis of the cases described provided confidence that the effect of credible single failures is bounded.

Decay Heat Model

American Nuclear Society (ANS) Standard 5.1 was used in the LOCA M&E release model for MPS3 for the determination of decay heat energy. This standard was balloted by the Nuclear Power Plant Standards Committee (NUPPSCO) in October 1978 and subsequently approved. The official standard was issued in August 1979. Table 2.6.3.1-4 lists the decay heat curve used in the MPS3 SPU Program M&E release analysis.

Significant assumptions in the generation of the decay heat curve for use in the LOCA M&E release analysis include the following:

- The decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.
- The decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.
- The fission rate is constant over the operating history of maximum power level.
- The factor accounting for neutron capture in fission products is taken from American ANS Standard 5.1 (Reference 4).
- The fuel is assumed to be at full power for 10^8 seconds.

- The total recoverable energy associated with one fission is assumed to be 200 MWV/fission.
- Two sigma uncertainty (two times the standard deviation) is applied to the fission product decay.

Based upon NRC staff review, (Safety Evaluation Report of the March 1979 evaluation model [Reference 1]), use of the ANS Standard-5.1, November 1979 decay heat model, was approved for the calculation of M&E releases to the containment following a LOCA.

Acceptance Criteria

The Standard Review Plan (SRP) long term cooling criterion is examined. A LBLOCA is classified as an ANS Condition IV event, an infrequent fault. To satisfy the NRC acceptance criteria presented in the SRP Section 6.2.1.3, the relevant requirements are as follows:

- 10 CFR 50, Appendix A
- 10 CFR 50, Appendix K, paragraph I.A

To meet these requirements, the following must be addressed:

- Sources of energy
- Break size and location
- Calculation of each phase of the accident

2.6.3.1.2.1.3 Description of Analyses and Evaluations

Description of Analyses

The evaluation model (EM) used for the long-term LOCA M&E release calculations (Blowdown and Refood) is the 1979 model described in WCAP-10325-P-A (Reference 1 & 6). The DEHL reflood used the WCAP-8264-P-A, "Topical Report Westinghouse Mass and Energy Release Data For Containment Design" (Reference 2) methodology. These EMs have been reviewed and approved by the NRC. The approval letters are included with Reference 1 and 2.

This report section presents the long-term LOCA M&E releases generated in support of the MPS3 SPU program. These M&E releases were used in the containment integrity analysis and qualification temperature evaluation (Section 2.6.1, Primary Containment Functional Design).

The M&E release rates described in this section form the basis of further computations to evaluate the containment following the postulated accident. Discussed in this section are the long-term LOCA M&E releases for the spectrum of breaks including the largest cold leg and hot leg breaks, and a range of pump suction breaks form the double-ended break with discharge coefficients 1.0 and 0.6 down to a 3.0 ft^2 split break. The M&E releases for these cases are shown in Tables 2.6.3.1-5 through 2.6.3.1-34. These cases are used for the long-term containment response analyses in Section 2.6.1, Primary Containment Functional Design and Section 2.6.5, Containment Heat Removal (RSS Pump NPSH Analysis).

LOCA M&E Release Phases

The containment system receives M&E releases following a postulated rupture in the RCS. These releases continue over a time period, which, for the LOCA M&E analysis, is typically divided into four phases.

- Blowdown – the period of time from accident initiation (when the reactor is at steady-state operation) to the time that the RCS and containment reach as equilibrium state.
- Refill – the period of time when the lower plenum is being filled by the accumulator and ECCS water. At the end of blowdown, a large amount of water remains in the cold legs, downcomer, and lower plenum. To conservatively consider the refill period for the purpose of containment M&E releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient water to completely fill the lower plenum. This allows an uninterrupted release of M&E to containment. Thus, the refill period is conservatively neglected in the M&E release calculation.
- Reflood – the period of time that begins when water from the lower plenum enters the core and ends when the core is completely quenched.
- Post-Reflood (GOTHIC) – the period of time following the reflood phase. At the end of reflood, the core has been recovered with water and the ECCS continues to supply water to the vessel. Depending on the location of the break, the two-phase mixture in the vessel may pass through the steam generator on the broken loop and acquire heat from the stored energy in the secondary system.

Computer Codes

The WCAP-10325-P-A (Reference 1) M&E release evaluation model comprises M&E release versions of the following codes: SATAN VI, WREFLOOD, FROTH, and EPITOME. SATANVI and WREFLOOD code were used to calculate the blowdown and reflood long-term LOCA M&E releases for MPS3. The post-reflood and long-term M&E release rates were calculated by the GOTHIC code using the methodology described in Reference 7 and 8.

SATAN VI calculates the blowdown phase, the first portion of the thermal-hydraulic transient following break initiation, including pressure, enthalpy, density, M&E flow rates, and energy transfer between primary and secondary systems as a function of time.

The WREFLOOD code addresses the portion of the LOCA transient where the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and when water supplied by the ECCS refills the reactor vessel and cools the core. The most important feature of WREFLOOD is the steam/water mixing model.

The FROTH code models the post-reflood portion of the transient. The post-reflood results from FROTH are not used, since this is provided by the GOTHIC methodology.

EPITOME continues the FROTH post-reflood portion of the transient from the time at which the secondary equilibrates to the containment design pressure to the end of the transient. It also compiles a summary of data for the entire transient, including formal instantaneous M&E release tables and M&E balance tables with data at critical times.

Break Size and Location

Generic studies have been performed and documented in Reference 1 with respect to the effect of postulated break size on the LOCA M&E releases. This section presents the mass and energy releases to the containment subsequent to a hypothetical LOCA. The release rates were calculated to support the SPU program and were calculated for pipe failures at three distinct locations:

1. Hot leg (between vessel and steam generator)
2. Pump suction (between steam generator and pump)
3. Cold leg (between pump and vessel)

During the reflood phase, these breaks have the following characteristics. For a cold leg pipe break, all of the fluid which leaves the core must vent through a steam generator and becomes super-heated. However, relative to breaks at other locations, the core flooding rate (and therefore the rate of fluid leaving the core) is low because all the core vent paths include the resistance of the reactor coolant pump. For a hot leg break, the vent path resistance is relatively low, which results in a high core flooding rate, and the majority of the fluid which exits the core bypasses the steam generators in venting to the containment. The pump suction break combines the effects of the relatively high core flooding rate, as in a hot leg break, and steam generator heat addition, as in the cold leg break. As a result, the pump suction breaks yield the highest energy flow rates during the post-blowdown period.

The spectrum of breaks analyzed includes the largest cold and hot leg breaks, and a range of pump suction breaks from the double ended break with discharge coefficients of 1.0 and 0.6 down to a 3.0 ft^2 split break. Because of the phenomena of reflood as discussed above, the pump suction break location is the worst case for long term containment depressurization. This conclusion is supported by studies presented in Reference 1 which included studies for hot leg and cold leg breaks. Thus, an analysis of smaller pump suction breaks is representative of the spectrum of break sizes. The hot leg break is the worst case for containment pressure due to the high short term blowdown release associated with this break location.

M&E Release Data

Blowdown M&E Release Data

The SATAN VI code was used for computing the blowdown transient. The code utilizes the control volume (element) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform and thermo-dynamic equilibrium is assumed in each element. A point kinetics model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature, and Doppler broadening. A critical flow calculation for subcooled (modified Zaloudek), two-phase (Moody), or superheated break flow is incorporated into the analysis. The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1).

Table 2.6.3.1-5 presents the calculated M&E release for the blowdown phase of the DEHL break. For the DEHL break M&E release tables, break path 1 refers to the M&E exiting form the reactor vessel side of the break; break path 2 refers to the M&E release exiting from the steam generator side of the break. Table 2.6.3.1-10 presents the calculated M&E releases for the blowdown phase of the DEPS break used for the minimum ECCS flow case and Table 2.6.3.1-15 presents the blowdown M&E for the maximum ECCS flow case. Table 2.6.3.1-20 presents the blowdown M&E for the DEPS break having a discharge coefficient (C_D) of 0.6. For the pump suction breaks, break path 1 in the M&E release tables refers to the M&E exiting from the steam generator side of the break. Break path 2 refers to the M&E exiting from the pump side of the break. Table 2.6.3.1-25 presents the blowdown M&E for the 3.0 ft^2 split break in the pump suction piping. Since this is a single ended break, data for one path is presented. Table 2.6.3.1-30 presents the blowdown data for the double-ended cold leg (DECL) break. For the DECL break, path 1 is the loop side of the break just downstream of the reactor coolant pump and path 2 is the vessel side of the break.

Reflood M&E Release Data

The WREFLOOD code is used for computing the reflood transient. The WREFLOOD code consists of two basic hydraulic models: one for the contents of the reactor vessel and one for the RCLs. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena such as pumped SI and accumulators, RCP performance, and steam generator release are included as auxiliary equations that interact with the basic models as required. The WREFLOOD code has the capability to calculate variations during the core reflooding transient of basic parameters such as core flooding rate, core and downcomer water levels, fluid thermo-dynamic conditions (pressure, enthalpy, and density) throughout the primary system, and mass flow rates through the primary system. The code permits hydraulic modeling of the two flow paths available for discharging steam and entrained water from the core to the break, that is, the path through the broken loop and the path through the unbroken loops.

A complete thermal equilibrium mixing condition for the steam and ECCS injection water during the reflood phase has been assumed for each loop receiving ECCS water. This is consistent with the usage and application of the WCAP-10325-P-A (Reference 1) M&E release evaluation model in recent analyses, for example, D. C. Cook Unit 1 Docket (Reference 3). Even though the WCAP-10325-P-A (Reference 1) model credits steam/water mixing only in the intact loop and not in the broken loop, the justification, applicability, and NRC approval for using the mixing model in the broken loop has been documented (Reference 3). Moreover, this assumption is supported by test data (Reference 5) and is further discussed below.

The model assumes a complete mixing condition (that is, thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of two distinct physical processes. The first is a two-phase interaction with condensation of steam by cold ECCS water. The second is a single-phase mixing of condensate and ECCS water. Since the steam release is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that need be considered. (Any spillage directly heats only the sump.)

The most applicable steam/water mixing test data have been reviewed for validation of the containment integrity reflood steam/water mixing model. This data was generated in 1/3-scale tests (Reference 5), which are the largest scale data available and thus most clearly simulates the flow regimes and gravitational effects that would occur in a PWR. These tests were designed specifically to study the steam/water interaction for PWR reflood conditions.

A group of 1/3-scale tests corresponds directly to containment integrity reflood conditions. The injection flow rates for this group cover all phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in WCAP-10325-P-A (Reference 1). For all these tests, the data clearly indicate the occurrence of very effective mixing with rapid steam condensation. The mixing model used in the containment integrity reflood calculation is, therefore, wholly supported by the 1/3-scale steam/water mixing data.

Additionally, the following justification is also noted. The post-blowdown limiting break for the containment integrity peak pressure analysis is the pump suction double-ended rupture. For this break, there are two flow paths available in the RCS by which M&E can be released to containment. One is through the outlet of the steam generator, the other via reverse flow through the RCP. Steam that is not condensed by ECCS injection in the intact RCS loops passes around the downcomer and through the broken-loop cold leg and RCP in venting to containment. This steam also encounters ECCS injection water as it passes though the broken-loop cold leg, complete mixing occurs, and a portion of it is condensed. It is this portion of steam that is condensed that is credited in this analysis. This assumption is justified based upon the postulated break location and the actual physical presence of the ECCS injection nozzle. A description of the test and test results are contained in WCAP-10325-P-A (Reference 1) and operating license Amendment No. 126 for D. C. Cook Unit 1 (Reference 3).

Table 2.6.3.1-6 presents the calculated reflood M&E for the DEHL break. The results were calculated using the model presented in Reference 2. Tables 2.6.3.1-11 and 2.6.3.1-16 present the calculated M&E releases for the reflood phase of the pump suction double-ended rupture, minimum safeguards, and maximum safeguards cases, respectively. Tables 2.6.3.1-21, 2.6.3.1-26, and 2.6.3.1-31 present the reflood M&E for the C_D =0.6, 3.0 ft^2 pump suction and the double-ended cold leg breaks.

The transient responses of the principal parameters during reflood are given in Tables 2.6.3.1-7, 2.6.3.1-12, 2.6.3.1-17, 2.6.3.1-22, 2.6.3.1-27 and 2.6.3.1-32.

Post-Reflood M&E Release Data

The Westinghouse methodology is used to determine the blowdown, refill and reflood mass and energy releases. The post-reflood mass and energy releases are determined using the NRC approved Dominion methodology discussed in Reference 7. As discussed in Reference 7 the Dominion model also accounts for the nitrogen releases from the accumulators. Benchmarking comparisons with the Westinghouse results were made to assure a seamless transfer between the two methodologies. The GOTHIC RCS model initialized to the same post-reflood conditions as predicted in the Westinghouse Analysis.

At the end of reflood, the core has been recovered with water and the ECCS continues to supply water to the vessel. Residual stored energy and decay heat comes from the fuel rods. Stored energy in the vessel and primary system metal will also be gradually released to the injection water and released to the containment via steaming through the core or spillage into the containment sump. In addition, there may be some buoyancy-driven circulation through the intact steam generator loops that will remove stored energy from the steam generator metal and water on the secondary side. Depending on the location of the break, the two-phase mixture in the vessel may pass through the steam generator on the broken loop and acquire heat from the stored energy in the secondary system. For these conditions, GOTHIC is capable of calculating the mass and energy release from the break into containment.

The GOTHIC long-term mass and energy release accounts for the transfer of the decay heat and the stored energy in the primary and secondary systems to the containment after the end of reflood. The energy for each source term is acquired at the end of reflood from the Westinghouse mass and energy release analysis. The rate of energy release is determined by a simplified, GOTHIC RCS model that is coupled to the containment volume. Thus, the flow from the vessel to the containment is dependent on the GOTHIC-calculated containment pressure.

Lumped volumes are used for the vessel, downcomer, cold legs, steam generator secondary side, up-flow steam generator tubes and down-flow steam generator tubes. Separate sets of loop and secondary system volumes are used for the intact and broken loops with the connections between the broken loop and containment as necessary for the modeled break location. The Westinghouse calculated mass and energy inventory at the end of reflood establishes the liquid volume fractions and the fluid temperatures in the primary and secondary systems.

The primary and secondary system geometries, including primary system resistances, are consistent with the models used for non-LOCA accident analyses. In order to predict the natural circulation through the intact loops and the correct water level in the vessel and downcomer, the volumes are modeled with the correct elevations and heights. The vessel height may be adjusted so that the water and steam inventory at the end of reflood matches the vendor’s boundary conditions, but this correction does not affect the hydraulic analysis.

Safety injection fluid is added to the intact and the broken loop cold leg volumes. In both locations, the SI fluid mixes with the resident fluid and any vapor from the intact SGs. The SI flow is taken from the RWST until the manual initiation of cold leg recirculation upon the annunciation of low-low level in the RWST, at which time the charging and intermediate head SI pumps are supplied water from the containment sump.

Steam Generator Modeling

Thermal conductors are used to model the transfer of energy stored in the shell side of the steam generator to the SG secondary fluid. The initial temperature is set to match the available stored energy specified at the end of reflood by the fuel vendor analysis. The up flow and down flow tubes on the steam generators are modeled separately with thermal conductors. This allows for the possibility of boiling in the up flow tubes and superheating of the steam in the down flow tubes. The heat transfer from the secondary side to the primary side is modeled using conductors with the inside connected to the primary system tube volumes. The Film heat transfer option is used on both sides of the tube. This option automatically accounts for heat transfer to the liquid or vapor phase as appropriate and includes boiling heat transfer modes.

Sources of M&E

The sources of mass considered in the LOCA M&E release analysis are given in Tables 2.6.3.1-8, 2.6.3.1-13, 2.6.3.1-18, 2.6.3.1-23, 2.6.3.1-28, and 2.6.3.1-33. These sources include the:

- RCS water
- Accumulator water
- Pumped injection (SI)

The energy inventories considered in the LOCA M&E release analysis are given in Tables 2.6.3.1-9, 2.6.3.1-14, 2.6.3.1-19, 2.6.3.1-24, 2.6.3.1-29, and 2.6.3.1-34. The energy sources are the following:

- RCS water
- Accumulator water
- Pumped injection (SI)
- Decay heat
- Core-stored energy
- RCS metal (includes steam generator tubes)
- Steam generator metal (includes transition cone, shell, wrapper, and other internals)
- Steam generator secondary energy (includes fluid mass and steam mass)
- Secondary transfer of energy (feedwater into and steam out of the steam generator secondary: feedwater pump coastdown after the signal to close the flow control valve)

The analysis used the following energy reference points:

- Available energy: 212°F: 14.7 psia (energy available that could be released)
- Total energy content: 32°F; 14.7 psia (total internal energy of the RCS)

The M&E inventories are presented at the following times, as appropriate:

- Time zero (initial conditions)
- End-of-blowdown time
- End-of-refill time
- End-of-reflood time

The energy release from the Zirconium-water reaction is considered as part of the WCAP-10325-P-A (Reference 1) methodology. Based on the way that the energy in the fuel is conservatively released to the vessel fluid, the fuel cladding temperature does not increase to the point were the Zirconium-water reaction is significant. This is in contrast to the 10 CFR 50.46 analyses, which are biased to calculate high fuel-rod-cladding temperatures and therefore a Zirconium-water reaction is considered. For the LOCA M&E calculation, the energy created by the Zirconium-water reaction value is small and is not explicitly provided in the energy balance tables. The energy that is determined is part of the M&E releases, and is therefore already included in the LOCA M&E release.

The sequences of events for the LOCA transients are shown inTables 2.6.3.1-35 through 2.6.3.1-40.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal Application for the impact on the Mass and Energy Release for Postulated Loss-of-Coolant Accidents. As stated in Section 2.6.3.1.1, The M&E release transients are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.6.3.1.2.1.4 M&E Release Analysis for Postulated LOCA Results

The LOCA M&E releases from accident initiation to the end of reflood, where applicable, have been provided for the DEHL and for the DEPS break cases. Post-reflood M&E releases were calculated internally to the GOTHIC containment model.

The M&E release transients for the limiting transients are presented in Tables 2.6.3.1-5 through 2.6.3.1-9 for the DEHL case. Tables 2.6.3.1-10 through 2.6.3.1-14 for the DEPS case with minimum ECCS flows and Tables 2.6.3.1-15 through 2.6.3.1-19 for the DEPS case with maximum ECCS flows.

No discussion is provided relative to margin change. The results of this analysis (M&E release rate transients) were used in the containment integrity analysis (see Section 2.6.1, Primary Containment Functional Design).

2.6.3.1.2.1.5 M&E Release Analysis for Postulated LOCA Conclusion

The consideration of the various energy sources listed in Section 2.6.3.1.2.1.2 for the long-term M&E release analysis provides assurance that all available sources of energy have been included in this analysis. By addressing all available sources of energy as well as the limiting break size and location and the specific modeling of each phase of the long-term LOCA transient, the review guidelines presented in SRP Section 6.2.1.3 have been satisfied.

2.6.3.1.2.1.6 M&E Release Analysis for Postulated LOCA References

1. WCAP-10325-P-A, May 1983 (Proprietary) and WCAP-10326-A (Nonproprietary), Westinghouse LOCA Mass and Energy Release Model for Containment Design, March 1979.

2. WCAP-8264-P-A, Rev. 1, August 1975 (Proprietary) and WCAP-8312-A, Rev. 2 (Nonproprietary) Topical Report Westinghouse Mass and Energy Release Data Containment Design.

3. Docket No. 50-315, Amendment No. 126, Facility Operating License No. DPR-58 (TAC No. 71062), for D. C. Cook Nuclear Plant Unit 1, June 9, 1989.

4. ANSI/ANS-5.1 1975, "American National Standard for Decay Heat Power in Light Water Reactors," August 1979.

5. EPRI 294-2, Mixing of Emergency Core Cooling Water with Steam; 1/3-Scale Test and Summary, WCAP-8423, Final Report, June 1975.

6. Mr. Herbert N. Berkow (NRC) to Mr. J. A. Gresham (W), "Acceptance Of Clarifications Of Topical Report WCAP-10325-P-A, 'Westinghouse LOCA Mass And Energy Release Model For Containment Design – March 1979 Version' (TAC NO. MC7980)," October 18, 2005.

7. Dominion Topical Report DOM-NAF-3-0.0-P-A, "GOTHIC Methodology for Analyzing the Response to Postulated Pipe Ruptures Inside Containment," September 2006.

8. NRC Letter "Kewaunee Power Station (Kewaunee), Millstone Power Station, Units Nos. 2 and 3 (Millstone 2 and 3), North Anna Power Station, Units Nos. 1 and 2 (North Anna 1 and 2) and Surry Power Station, Unit Nos. 1 and 2 (Surry 1 and 2) – Approval of Dominion's Topical Report DOM-NAF-3, "GOTHIC Methodology for Analyzing the Response to Postulated Pipe Ruptures Inside Containment" (TAC Nos. MC8831, MC8832, MC8833, MC8834, MC8835, and MC8836)" dated August 30, 2006.

2.6.3.1.2.2 Short-Term LOCA M&E Releases

An evaluation was conducted to determine the effect of the MPS3 SPU program on the short-term LOCA-related M&E releases that support the subcompartments discussed in the FSAR Section 6.2.1.2.

2.6.3.1.2.2.1 Introduction

The containment internal structures are designed for a pressure buildup that could occur following a postulated LOCA. If a LOCA were to occur in these relatively small volumes, the pressure would build up at a faster rate than the overall containment, thus imposing a differential pressure across the walls of the compartments. The evaluation of the containment internal structures is discussed in FSAR Section 6.2.1.2.

Short-term LOCA M&E release calculations are performed to support the lower steam generator subcompartment, upper reactor cavity, lower pressurizer cubicle and the upper pressurizer cubicle. The current licensing basis for these structures are 1) a 707 square inch hot leg intrados split break, 2) a 100 square inch cold leg limited displacement break, 3) a double ended break in the pressurizer surge line and 4) a double ended break in the pressurizer spray line, respectively. Additional smaller breaks used for the major component support evaluation are identified in the discussion of the results in FSAR Section 6.2.1.2.3. These analyses are performed to ensure that the walls in the immediate proximity of the break location can maintain their structural integrity during the short-pressure pulse (generally less than 3 seconds) that accompanies a LOCA within the region.

MPS3 has been approved for LBB methods (Reference 1). With the elimination of the large RCS breaks, the only break locations that need to be considered are the largest branch lines off of the primary loop piping. These branch lines include the pressurizer surge line, the pressurizer spray line, the accumulator line, and the RHR line from the hot leg to the first isolation valve. The releases associated with these smaller breaks would be considerably lower than the large RCS breaks.

2.6.3.1.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The short-term LOCA M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are utilized and instrumentation uncertainties are included. For example, the RCS operating temperatures were chosen to bound the temperature range of all operating cases and a temperature uncertainty allowance (-4°F) was then included. Nominal parameters are used in certain instances. For example, the RCS pressure in this analysis is based on a nominal value of 2250 psia plus an uncertainty allowance (+50 psi). All input parameters are chosen consistent with accepted analysis methodology. The blowdown M&E release rates are affected by the initial RCS temperature conditions. Since short-term releases are linked directly to the critical mass flux, which increases with increasing pressures and decreasing temperatures, the short-term LOCA releases are expected to increase due to changes associated with the RCS SPU conditions including a T_{avg} coastdown.

Increased power has no impact on the short-term releases because of the duration of the event (i.e., ~2.0 seconds). Only changes in the initial RCS pressure and temperature conditions would affect the results.

For the M&E releases, the core-stored energy and flow behavior through the core have the potential of changing as a result of a fuel change. However, any changes to the flow characteristics past the fuel are assumed small, and as such, would have an insignificant impact on the short-term LOCA M&E releases. Any possible change in the core-stored energy does not adversely affect the normal plant operating parameters, system actuations, accident mitigating capabilities or assumptions important to the short-term LOCA M&E releases. This change does not create conditions more limiting than those assumed in the analyses. Any change in core-stored energy would have no affect on the releases because of the short duration of the postulated accident.

Therefore, the only effects that need to be addressed are the change in RCS coolant temperatures and the changes in analysis assumptions for RCS coolant pressure.

In summary, the following assumptions were employed to ensure that the M&E releases were conservatively calculated, thereby maximizing mass release to containment subcompartment

- RCS vessel outlet temperature goes from 622.6° to 605.6°F
- RCS vessel/core inlet temperature goes from 556.4° to 537.4°F
- Allowance for RCS temperature uncertainty (-4.0°F)
- Allowance for RCS pressure uncertainty is + 50 psi

Acceptance Criteria

MPS3 is a Standard Review Plan (SRP) plant and therefore the SRP short-term cooling criterion is also examined. A LOCA is classified as an ANS Condition IV event – an infrequent fault. To satisfy the NRC acceptance criteria presented in SRP Section 6.2.1.3, the relevant requirements are as following:

- The NRC's NUREG-0800, Section 6.2.1.3, M&E Release Analysis for Postulated Loss-of-Coolant Accidents, Subsection II, Part 3a provides guidance on NRC's expectations for what must be included in a LOCA M&E release calculation, if that calculation is to be acceptable. The Westinghouse M&E models described in WCAP-8264-P-A, Rev. 1 (Reference 2) have been found by the NRC to satisfy those expectations.

2.6.3.1.2.2.3 Description of Analysis and Evaluations

Description of Analysis

Short-term releases are linked directly to the critical mass flux, which increases with increasing pressures and decreasing temperatures. The short-term LOCA releases are expected to increase due to changes associated with the current RCS conditions. Short-term blowdown transients are characterized by a peak M&E release rate that occurs during a subcooled condition; thus the Zaloudek correlation, which models this condition, is currently used in the short-term LOCA M&E release analyses (Reference 2). This correlation was used to conservatively evaluate the impact of the deviations in the RCS inlet and outlet temperature for the SPU program. Therefore, using lower temperatures maximizes the short-term LOCA M&E releases.

As previously stated, MPS3 has been approved for LBB methods (Reference 1). With the elimination of the large RCS breaks, the only break locations that need to be considered are the largest branch lines off of the primary loop piping. These branch lines include the pressurizer surge line, the pressurizer spray line, the accumulator line and the RHR line from the hot leg to the first isolation valve. The releases associated with these smaller breaks are considerably lower than the large RCS breaks

Short-term LOCA M&E release calculations are performed to support the lower steam generator subcompartment, upper reactor cavity, lower pressurizer cubicle and the upper pressurizer cubicle. The current licensing basis for these structures are 1) a 707 square inch hot leg intrados split break, 2) a 100 square inch cold leg limited displacement break, 3) a double ended break in the pressurizer surge line and 4) a double ended break in the pressurizer spray line, respectively.

Leak before break has eliminated the 707 square inch hot leg intrados split break from consideration for subcompartment pressurization. The reduction in break area for the lower steam generator compartments comparing the 707 square inch hot leg intrados split break to a double-ended break in the pressurizer surge line is a ratio of about 3.6. A reduction of this magnitude in pipe break size has been shown to have a significant impact on the subcompartment loadings. For example, based upon available sensitivities (Reference 3), it is estimated that the peak break compartment pressure was shown to be reduced by a factor of 2.76, and the peak differential across an adjacent wall was reduced by a factor of 3.86.

The 100 square inch cold leg limited displacement break for the upper reactor cavity has been completely eliminated by the application of LBB and no further consideration is required.

The release calculations for the pressurizer lower and upper cubicles are limited by the pressurizer surge line and the pressurizer spray line, respectively. These breaks have not been eliminated by LBB and therefore must be evaluated for the MPS3 SPU program.

The pressurizer spray line break LOCA M&E analyzed for MPS3 are found in FSAR Table 6.2-31 and were taken from Reference 2, Table III-2-5. These mass and energy releases are based on a RCS cold leg temperature of 561.3°F and pressurizer saturated liquid temperature at 2280 psia. The MPS3 SPU program could potentially operate with a RCS cold leg temperature as low as 533.4°F and an RCS pressure as high as 2300 psia in the pressurizer. These changes in RCS conditions of pressure and temperature could increase the spray line mass and energy releases by as much as 3.4 percent. The increase lies within the 10 percent residual margin applied to the FSAR Table 6.2-31 release and therefore the MPS3 spray line mass and energy releases documented in FSAR Table 6.2-31 bound MPS3 SPU operation.

The pressurizer surge line break LOCA M&E analyzed for MPS3 are found in FSAR Table 6.2-32 and 6.2-32A and were taken from Reference 2, Table III-2-6. These mass and energy releases are based on a RCS hot leg temperature of 623.9°F and pressurizer saturated liquid temperature at 2280 psia. The MPS3 SPU program could potentially operate with a RCS hot leg temperature as low as 601.6ºF and an RCS pressure as high as 2300 psia in the pressurizer. These changes in RCS conditions of pressure and temperature could increase the surge line mass and energy releases by as much as 15.75 percent on mass released and 11.27 percent on energy released. FSAR Table 6.2-32 is the pressurizer surge line break with the 10 percent margin factor removed. Thus, the mass/energy releases could increase by 15.75/11.27 percent for those pressurizer cubicle nodes based on FSAR Table 6.2-32. Pressurizer cubicle nodes based on the LOCA mass and energy releases in FSAR Table 6.2-32A which includes the 10 percent margin would see a potential increase of 5.23/1.15 percent. The affect these increases could have on the pressurizer cubicle differential pressures and the steam generator cubicle differential pressures are discussed in Section 2.6.2.

The steam generator compartment RHR line break is addressed in FSAR Section 6.2.1.2, "Containment subcompartments," and Subsection 6.2.1.2.3 "Design Evaluation," which describes the breaks analyzed for the steam generator compartment. They are as follows:

1. Steam Generator inlet nozzle with a 196.6 sq in. LDR
2. Pressurizer surge line with a 196.6 sq in. LDR
3. Residual heat removal line with 196.6 sq in. LDR
4. RCS hot leg intrados split break with 707 sq in opening
5. Feedwater line 238.8 sq in. SES.
6. Steam generator outlet nozzle LDR with 500 sq in. opening

7. Pump suction loop closure weld LDR with 500 sq in. opening.

Breaks 1, 4, 6 and 7 have been eliminated due to the application of leak before break. Break 5, the feedwater line break, is not a LOCA and is outside the scope of this LOCA evaluation. Break 2 the pressurizer surge line break has already been evaluated. Thus, only break 3, the residual heat removal line, needs to be evaluated. The FSAR states that the 196.6 sq in. pressurizer surge line break releases were used in lieu of the RHR line break releases. The RHR line break for a 12 inch schedule 140 pipe would have a single-ended break area of 0.6013 ft^2 or 86.59 sq in. This break is approximately 44 percent the size of the pressurizer surge line break. This reduction in the break area for the actual RHR line more than offsets the increases seen for the pressurizer surge line break. Thus, the existing 196.6 sq inch LDR break used in lieu of the RHR line break for the steam generator subcompartment and the results shown in FSAR Table 6.2-39 bound Millstone Unit 3 SPU operation including the proposed T_{avg} coastdown.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal Application for the impact on the Mass and Energy Release for Postulated Loss-of-Coolant Accidents. As stated in Section 2.6.3.1.1, the M&E release transients are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.6.3.1.2.2.4 Short-Term LOCA M&E Releases Results

In summary, the effect of eliminating the large RCS breaks through LBB and considering the branch nozzles is more than a factor of 3 (300 percent) reduction in the break area, whereas the penalty associated with the uprate is only 15.75/11.27 percent. LBB has not eliminated the pressurizer spray line and surge line breaks that can see increases due to the MPS3 SPU operating pressures and temperatures. The affect these increases are discussed in Section 2.6.2.

2.6.3.1.2.2.5 Short-Term LOCA M&E Releases Conclusion

The LOCA mass and energy releases presented in the FSAR Chapter 6.2 have been evaluated to determine the affect of the SPU program and the proposed T_{avg} coastdown on the short term LOCA mass and energy releases. All breaks with the exception of the pressurizer spray line, pressurizer surge line and the RHR line have been eliminated by leak before break. The increases for the pressurizer spray line break were shown to be bounded by the 10 percent margin previously added on to these M&Es. Thus, the existing spray line break mass and energy releases found in FSAR Table 6.2-31 bound Millstone Unit 3 SPU operation including the proposed T_{avg} coastdown. Since the much larger pressurizer surge line break was used in lieu of the smaller RHR line break for the steam generator compartment the current FSAR analysis for the steam generator subcompartment bounds Millstone Unit 3 SPU operation including the proposed T_{avg} coastdown. The increases for the pressurizer surge line M&E are addressed in Section 2.6.2.

2.6.3.1.2.2.6 Short-Term LOCA M&E Releases References

1. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, Docket Nos. 50-336 and 50-423, Dominion Nuclear Connecticut, Inc.,” October 2005.

2. WCAP-8264-P-A, Rev. 1, August 1975 (Proprietary) and WCAP-8312-A, Rev. 2 (Nonproprietary), Topical Report Westinghouse Mass and Energy Release Data Containment Design.

3. WCAP-12035, Containment Subcompartment Analysis Utilizing Leak Before Break Technology for Watts Bar Units 1 and 2, November 1988.

2.6.3.1.2.3 Conclusion

DNC has reviewed the M&E release assessment and concludes that it has adequately addressed the effects of the SPU and appropriately accounts for the sources of energy identified in 10 CFR 50, Appendix K. Based on this, DNC finds that the M&E release analysis will continue to meet the MPS3 current licensing basis with respect to the requirements in GDC-50 for ensuring that the analysis is conservative. Therefore, DNC finds the SPU acceptable with respect to M&E release for postulated LOCA.

Table 2.6.3.1-1
System Parameters Initial Conditions

Parameters	**Value**
Core Thermal Power (MWt)	3650.0
RCS Total Flow Rate (Lbm/sec)	37,343.6
Vessel Outlet Temperature[(a)] (°F)	627.6
Core Inlet Temperature[(a)] (°F)	561.4
Vessel Average Temperature[(a)] (°F)	594.5
Initial Steam Generator Steam Pressure (psia)	948
Steam Generator Design	F
SGTP (%)	0
Initial Steam Generator Secondary Side Mass (Lbm)	128,622.0
Assumed Maximum Containment Backpressure (psia)	Variable – Refer to Section 2.6.1
Accumulator Water volume (ft^3) per accumulator (minimum)[(b)] N_2 cover gas pressure (psia) (minimum) Temperature (°F)	 884.7 664.7 120
SI Start Time, (sec) [total time from beginning of event, which includes the maximum delay from reaching the setpoint]	45.3
Auxiliary Feedwater Flow (gpm/steam generator) (Minimum Safeguards)	0
Auxiliary Feedwater Flow (gpm/steam generator) (Maximum Safeguards)	0

Notes:
Core thermal power, RCS total flow rate, RCS coolant temperatures, and steam generator secondary side mass include appropriate uncertainty and/or allowance.
RCS coolant temperatures include +4.0°F allowance for instrument error and deadband and a +1.0ºF bias.

a. Does not include accumulator line volume.

Table 2.6.3.1-2
SI Flow Minimum Safeguards

RCS Pressure (psia)	Total Flow (gpm)
Injection Mode (Reflood phase)	
14.7	4,793.9
54.7	4,269.2
114.7	3,231.9
154.7	1,913.88
174.7	930.22
Recirculation Mode	
RCS Pressure (psia)	**Total Flow (gpm)**
14.7	978.8
114.7	948.7

Table 2.6.3.1-3
SI Flow Maximum Safeguards

RCS Pressure (psia)	Total Flow (gpm)
Injection Mode (Reflood phase)	
14.7	11,734.1
54.7	10,718.3
114.7	8,908.45
154.7	7,355.76
174.7	6,378.52
Recirculation Mode	
RCS Pressure (psia)	**Total Flow (gpm)**
14.7	1,753

Table 2.6.3.1-4
LOCA M&E Release Analysis Core Decay Heat Fraction

Time (sec)	Decay Heat Generation Rate (Btu/Btu)
10	0.053876
15	0.050401
20	0.048018
40	0.042401
60	0.039244
80	0.037065
100	0.035466
150	0.032724
200	0.030936
400	0.027078
600	0.024931
800	0.023389
1000	0.022156
1500	0.019921
2000	0.018315
4000	0.014781
6000	0.013040
8000	0.012000
10,000	0.011262
15,000	0.010097
20,000	0.009350
40,000	0.007778
60,000	0.006958
80,000	0.006424
100,000	0.006021
150,000	0.005323
200,000	0.004847

Table 2.6.3.1-4
LOCA M&E Release Analysis Core Decay Heat Fraction

Time (sec)	Decay Heat Generation Rate (Btu/Btu)
400,000	0.003770
600,000	0.003201
800,000	0.002834
1,000,000	0.002580
2,000,000	0.001909
4,000,000	0.001355

Table 2.6.3.1-5
DEHL Break Blowdown M&E Release

	Break Path No.1*		Break Path No.2**	
Time Seconds	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
.0000	.0	.0	.0	.0
.0016	47925.4	31272.5	47924.2	31270.6
.101	42005.0	27693.0	27265.4	17750.0
.202	37069.8	24367.9	24054.3	15563.1
.301	36328.3	23809.4	21261.6	13569.3
.402	35134.3	23008.2	19866.7	12445.8
.502	34464.9	22567.8	19033.7	11709.3
.601	34401.5	22533.5	18488.1	11194.1
.702	33995.2	22312.0	18056.7	10784.6
.802	33238.7	21892.8	17754.7	10486.0
.901	32500.6	21505.2	17541.1	10263.4
1.00	32114.5	21367.4	17371.0	10084.4
1.10	31771.5	21265.0	17317.1	9986.4
1.20	31351.4	21105.4	17341.7	9941.0
1.30	30793.2	20843.8	17404.6	9924.1
1.40	30151.6	20512.2	17492.0	9927.5
1.50	29541.2	20190.2	17592.9	9944.0
1.60	29046.1	19939.2	17698.4	9969.0
1.70	28605.4	19720.3	17797.3	9996.2
1.80	28083.0	19436.8	17879.8	10019.6
1.90	27443.6	19058.2	17939.0	10034.9
2.00	26791.1	18658.2	17974.9	10041.6
2.10	26240.5	18325.1	17992.3	10041.5
2.20	25778.2	18053.1	17992.6	10034.8
2.30	25304.0	17764.8	17973.7	10020.0

Table 2.6.3.1-5
DEHL Break Blowdown M&E Release

	Break Path No.1*		Break Path No.2**	
Time Seconds	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
2.40	24791.1	17437.1	17934.3	9995.8
2.50	24285.1	17104.5	17877.8	9963.8
2.60	23816.2	16791.5	17808.1	9925.7
2.70	23412.1	16522.4	17727.9	9882.8
2.80	23043.3	16275.8	17638.0	9835.3
2.90	22671.4	16018.2	17539.4	9783.7
3.00	22321.0	15768.4	17430.3	9726.7
3.10	21995.8	15531.9	17313.1	9665.7
3.20	21691.3	15304.8	17190.9	9602.1
3.30	21430.1	15105.9	17064.4	9536.4
3.40	21191.9	14920.4	16933.2	9468.2
3.50	20963.3	14737.0	16794.9	9396.3
3.60	20761.9	14570.1	16649.5	9320.5
3.70	20579.1	14414.5	16500.7	9242.9
3.80	20412.2	14268.1	16343.3	9160.7
3.90	20267.3	14137.0	16176.9	9073.4
4.00	20138.7	14017.0	15989.0	8974.0
4.20	19970.9	13839.9	15508.6	8716.7
4.40	19856.4	13705.1	15033.9	8464.0
4.60	19813.4	13616.1	14607.7	8238.7
4.80	19842.7	13562.4	14303.8	8081.4
5.00	19898.7	13522.6	13871.5	7847.2
5.20	19980.1	13492.0	13454.1	7621.6
5.40	20075.3	13462.3	13113.9	7439.5
5.60	20190.5	13443.6	12808.1	7275.8

Table 2.6.3.1-5
DEHL Break Blowdown M&E Release

	Break Path No.1*		Break Path No.2**	
Time Seconds	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
5.80	20330.2	13442.6	12518.5	7119.7
6.00	20490.3	13453.2	12207.1	6950.1
6.20	20664.6	13472.0	11923.1	6796.1
6.40	20874.7	13514.6	11664.6	6656.6
6.60	21179.7	13607.7	11413.5	6520.8
6.80	16347.8	11465.9	11164.7	6385.7
7.00	16248.3	11315.0	10912.2	6248.5
7.20	16297.0	11244.4	10666.8	6115.1
7.40	16388.7	11282.1	10447.2	5996.4
7.60	16447.6	11269.0	10221.7	5873.6
7.80	16462.3	11191.0	9996.0	5750.6
8.00	16528.6	11192.6	9777.4	5631.9
8.20	16593.9	11150.1	9564.2	5516.4
8.40	16606.5	11118.5	9353.8	5402.6
8.60	16613.2	11053.1	9143.0	5288.7
8.80	16664.0	11039.1	8934.2	5176.1
9.00	16497.9	10915.9	8727.7	5065.2
9.20	16386.0	10787.2	8524.4	4956.4
9.40	16456.1	10771.1	8317.9	4846.0
9.60	16508.2	10748.9	8117.7	4739.7
9.80	16531.3	10712.5	7918.5	4634.2
10.0	16513.4	10654.9	7724.2	4531.7
10.2	16468.0	10584.3	7533.2	4431.4
10.4	16393.6	10499.5	7343.0	4331.8
10.6	16283.7	10397.7	7157.3	4235.1

Table 2.6.3.1-5
DEHL Break Blowdown M&E Release

	Break Path No.1*		Break Path No.2**	
Time Seconds	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
10.8	16134.2	10277.6	6976.0	4141.0
11.0	15942.1	10136.9	6797.0	4048.4
11.2	15715.9	9981.0	6623.2	3959.0
11.4	15464.2	9813.7	6451.7	3871.2
11.6	15202.2	9643.4	6284.0	3785.8
11.8	14939.8	9475.5	6120.7	3703.1
12.0	14683.4	9313.7	5966.0	3625.2
12.2	14421.4	9151.3	5814.1	3548.8
12.4	14158.3	8990.4	5669.9	3476.6
12.6	13889.7	8829.5	5532.2	3407.7
12.8	13608.3	8663.5	5396.4	3340.0
13.0	13326.9	8500.3	5268.3	3276.1
13.2	13036.1	8334.0	5143.1	3213.8
13.4	12745.4	8170.2	5023.4	3154.3
13.6	12451.7	8007.2	4907.1	3096.6
13.8	12161.5	7848.8	4796.3	3041.6
14.0	11862.8	7688.3	4687.1	2987.6
14.2	11558.5	7527.3	4582.4	2935.6
14.4	11220.7	7350.5	4476.1	2882.8
14.6	10859.9	7164.2	4366.7	2828.4
14.8	10470.6	6965.6	4247.1	2769.5
15.0	10061.1	6760.3	4112.8	2705.2
15.2	9650.4	6557.8	3963.8	2635.5
15.4	9188.5	6411.9	3798.0	2558.7
15.6	8025.9	6181.9	3628.7	2481.2

Table 2.6.3.1-5
DEHL Break Blowdown M&E Release

	Break Path No.1*		Break Path No.2**	
Time Seconds	**Mass lbm/sec**	**Energy Thousand btu/sec**	**Mass lbm/sec**	**Energy Thousand btu/sec**
15.8	7354.1	6077.6	3459.0	2402.0
16.0	6709.7	5883.2	3294.0	2322.1
16.2	6109.7	5505.1	3140.6	2244.2
16.4	5512.2	5052.7	3000.7	2171.3
16.6	5043.8	4709.5	2871.4	2103.5
16.8	4738.0	4517.2	2749.2	2041.3
17.0	4493.7	4338.6	2628.8	1983.8
17.2	4242.6	4161.1	2509.5	1930.7
17.4	3982.6	3978.1	2391.6	1879.5
17.6	3701.4	3776.3	2275.7	1830.4
17.8	3424.1	3572.8	2163.7	1784.8
18.0	3139.8	3377.8	2056.5	1741.4
18.2	2855.7	3179.4	1953.9	1699.2
18.4	2586.3	2982.1	1853.6	1657.6
18.6	2369.5	2800.9	1754.2	1618.7
18.8	2217.1	2659.4	1651.4	1584.9
19.0	2127.9	2578.6	1549.8	1547.0
19.2	2036.8	2467.0	1457.1	1513.4
19.4	1935.7	2348.1	1375.6	1476.7
19.6	1826.3	2221.6	1309.8	1443.1
19.8	1717.7	2095.8	1256.4	1413.3
20.0	1624.8	1983.1	1209.1	1380.4
20.2	1527.8	1868.4	1171.9	1349.8
20.4	1428.8	1759.6	1136.2	1320.3
20.6	1342.4	1661.0	1093.6	1287.2

Table 2.6.3.1-5
DEHL Break Blowdown M&E Release

	Break Path No.1*		Break Path No.2**	
Time Seconds	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
20.8	1263.4	1568.0	1023.2	1232.0
21.0	1181.6	1470.0	937.1	1144.1
21.2	1105.3	1376.9	859.3	1054.9
21.4	1023.8	1278.1	792.4	976.5
21.6	958.7	1197.0	730.7	902.2
21.8	906.7	1131.9	601.2	743.6
22.0	866.9	1078.2	533.7	662.1
22.2	567.6	716.4	441.5	549.5
22.4	237.9	299.7	266.3	332.1
22.6	221.0	279.7	125.3	157.6
22.8	56.5	71.2	122.6	155.3
23.0	.0	.0	99.1	126.2
23.2	.0	.0	129.5	164.7
23.4	.0	.0	.0	.0

Notes:
*Path 1: M&E exiting from the reactor vessel side of the break.
**Path 2:M&E exiting from the steam generator side of the break.

Table 2.6.3.1-6
Double Ended Hot Leg Minimum Safety Injection
Reflood 8264 Mass and Energy Releases

Time	Steam Release		Water Release	
Second	**lbm/sec**	**1000 btu/sec**	**lbm/sec**	**1000 btu/sec**
23.4	96.0	112.7	.0	.0
23.6	.0	.0	.0	.0
23.7	71.4	15.6	.0	.0
23.8	1222.8	450.5	.0	.0
24.0	572.7	452.4	.0	.0
26.4	1581.9	696.1	.0	.0
29.5	2418.5	880.2	.0	.0
50.0	2143.0	761.1	.0	.0
56.7	2043.4	724.1	.0	.0
58.5	1781.3	674.7	.0	.0
64.6	1083.9	543.7	.0	.0
73.1	655.2	460.5	.0	.0
84.3	450.2	416.1	.0	.0
97.3	394.4	397.6	.0	.0
100.0	392.6	395.6	.0	.0
152.2	382.0	364.6	.0	.0

Table 2.6.3.1-7
Double Ended Hot Leg Break With Minimum ECCS Flows — Reflood 8264 Principal Parameters

Time*	Flooding		Carryover Fraction	Core Height	Downcomer Height	Flow Fraction	Injection			
	Temp	Rate					Total	Accumulator	Spilt	Enthalpy
sec	ºf	in/sec	(---)	ft	ft	(---)	(cubic feet per sec)			btu/lbm
0.00	288.21	0.000	0.000	0.00	0.00	0.250	0.0	0.0	0.0	68.03
0.21	283.15	58.865	0.000	0.55	0.07	0.999	145.8	145.8	0.0	94.07
0.30	278.70	75.686	0.001	1.06	-0.30	0.779	145.2	145.2	0.0	94.09
0.31	278.16	76.991	0.004	1.12	-0.35	0.766	145.2	145.2	0.0	94.09
0.45	274.65	8.208	0.380	1.50	-0.47	0.899	141.4	141.4	0.0	93.98
0.61	274.22	4.960	0.423	1.55	0.08	0.882	142.2	142.2	0.0	94.09
2.96	266.71	8.019	0.748	2.00	7.28	0.910	125.8	125.8	0.0	94.36
6.11	252.86	11.069	0.833	2.50	14.03	0.906	105.9	105.9	0.0	94.65
7.01	248.74	11.573	0.841	2.64	15.46	0.904	101.0	101.0	0.0	94.76
8.01	244.37	11.512	0.847	2.79	16.12	0.904	97.6	97.6	48.6	94.93
9.50	238.59	11.273	0.853	3.00	16.12	0.905	93.6	93.6	45.6	95.19
13.29	226.91	10.819	0.859	3.50	16.12	0.906	84.9	84.9	38.8	95.86
17.34	217.84	10.419	0.861	4.00	16.12	0.907	77.5	77.5	33.1	96.56
21.55	210.91	10.034	0.860	4.50	16.12	0.907	79.2	71.2	36.4	87.48
25.90	205.27	9.651	0.859	5.00	16.12	0.908	73.9	65.8	32.8	87.30
30.39	200.40	9.266	0.858	5.50	16.12	0.909	69.4	61.2	30.0	87.11
32.01	198.83	9.129	0.857	5.68	16.12	0.909	67.9	59.7	29.1	87.04

Table 2.6.3.1-7
Double Ended Hot Leg Break With Minimum ECCS Flows — Reflood 8264 Principal Parameters

Time*	Flooding		Carryover Fraction	Core Height	Downcomer Height	Flow Fraction	Injection			
	Temp	Rate					Total	Accumulator	Spilt	Enthalpy
sec	ºf	in/sec	(---)	ft	ft	(---)	(cubic feet per sec)			btu/lbm
33.34	197.61	9.020	0.857	5.82	16.11	0.909	8.3	0.0	0.0	68.03
35.09	196.15	7.880	0.853	6.00	14.72	0.910	8.5	0.0	0.0	68.03
41.21	193.05	4.916	0.830	6.50	11.58	0.904	9.0	0.0	0.0	68.03
49.68	192.01	3.015	0.799	7.00	9.84	0.888	9.2	0.0	0.0	68.03
60.91	192.77	2.172	0.777	7.50	9.40	0.872	9.3	0.0	0.0	68.03
73.92	194.27	1.937	0.769	8.00	9.66	0.866	9.3	0.0	0.0	68.03
87.52	195.72	1.890	0.768	8.50	10.14	0.865	9.3	0.0	0.0	68.03
101.26	196.81	1.882	0.768	9.00	10.67	0.865	9.3	0.0	0.0	68.03
110.01	197.28	1.881	0.769	9.32	11.00	0.865	9.3	0.0	0.0	68.03
115.05	197.47	1.881	0.769	9.50	11.20	0.865	9.3	0.0	0.0	68.03
128.85	197.66	1.882	0.769	10.00	11.73	0.865	9.3	0.0	0.0	68.03

* Time is reflood time. Transient time is reflood time plus 23.4 seconds.

Table 2.6.3.1-8
Double Ended Hot Leg Break With Minimum ECCS Flows
Post 8264 Methods — Mass Balance

	Time (Seconds)	**0.0**	**23.4**	**23.4+ε***	**152.25**
		Mass (Thousands lbm)			
INITIAL	IN RCS AND ACCUMULATOR	744.62	744.62	744.62	744.62
ADDED MASS	PUMPED INJECTION	.00	.00	.00	66.95
	TOTAL ADDED	.00	.00	.00	66.95
*** TOTAL AVAILABLE ***		744.62	744.62	744.62	811.57
DISTRIBUTION	REACTOR COOLANT	517.02	77.27	115.19	163.40
	ACCUMULATOR	227.59	170.22	132.30	.00
	TOTAL CONTENTS	744.62	247.49	247.49	163.40
EFFLUENT	BREAK FLOW	.00	497.10	497.10	619.52
	ECCS SPILL	.00	.00	.00	28.61
	TOTAL EFFLUENT	.00	497.10	497.10	648.13
*** TOTAL ACCOUNTABLE ***		744.62	744.62	744.60	811.54

- +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

Table 2.6.3.1-9 Double Ended Hot Leg Break With Minimum ECCS Flows Post 8264 Methods — Energy Balance

	Time (Seconds)	0.0	23.4	23.4+ε*	152.25
		Energy (Millions btu)			
Initial Energy	In RCS, Accumulators and Steam Generators	851.30	851.30	851.30	851.30
Added Energy	Pumped Injecti0n	.00	.00	.00	4.58
	Decay Heat	.00	8.35	8.35	25.39
	Heat from Secondary	.00	9.77	9.77	9.77
	Total Added	.00	18.11	18.11	39.75
*** Total Available ***		851.30	869.41	869.41	891.05
Distribution	Reactor Coolant	308.07	19.18	22.58	30.91
	Accumulator	20.41	15.26	11.86	.00
	Core Stored	24.79	9.90	9.90	4.43
	Primary Metal†	153.93	145.27	145.27	118.08
	Thin Metal	15.31	7.41	7.41	.00
	Thick Metal	138.62	137.86	137.86	118.08
	Secondary Metal	52.81	51.95	51.95	50.82
	Steam Generator	291.30	299.97	299.97	290.38
	Total Contents	851.30	541.52	541.52	494.61
Effluent	Break Flow	.00	327.29	327.29	393.32
	ECCS Spill	.00	.00	.00	2.52
	Total Effluent	.00	327.29	327.29	395.84
*** Total Accountable ***		851.30	868.81	868.81	890.45

* - +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

† - Primary metal is considered to be composed of thin and thick metal. Thus, the sum of the “Thin” and “Thick” metal energies in the table is equal to the “Primary Metal”. The WCAP-8264-P-A methodology uses thin and thick metal which is not specifically listed for the WCAP-10325-P-A methodology.

Table 2.6.3.1-10
DEPS Break Blowdown M&E Release
(applicable for DEPS Minimum safeguards cases)

Time	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass	Energy	Mass	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
0.0000	0.0	0.0	0.0	0.0
0.0019	88647.9	49448.7	42509.5	23658.5
0.101	41991.5	23439.0	21609.6	12013.9
0.202	42476.2	23866.2	24072.5	13395.3
0.301	43153.3	24464.4	24420.1	13601.0
0.402	43945.7	25193.4	23736.4	13233.5
0.502	44491.2	25815.1	22681.0	12654.4
0.602	44450.8	26095.7	21804.6	12170.8
0.702	43621.4	25879.7	21026.6	11739.3
0.802	42312.2	25337.6	20407.1	11395.5
0.901	40924.1	24709.5	19992.7	11168.0
1.00	39626.8	24106.8	19755.6	11038.2
1.10	38505.6	23592.2	19614.0	10961.0
1.20	37581.3	23188.0	19524.0	10911.6
1.30	36804.6	22870.7	19460.1	10876.1
1.40	36121.8	22608.4	19414.2	10850.1
1.50	35472.3	22371.3	19384.4	10832.7
1.60	34816.2	22134.0	19374.4	10826.5
1.70	34122.2	21882.4	19371.5	10824.1
1.80	33377.1	21603.0	19351.3	10811.9
1.90	32467.4	21223.6	19304.4	10784.6
2.00	31557.7	20837.8	19237.5	10745.9
2.10	30583.3	20403.0	19143.4	10692.2
2.20	29611.2	19957.0	19031.6	10628.8

Table 2.6.3.1-10
DEPS Break Blowdown M&E Release
(applicable for DEPS Minimum safeguards cases)

Time	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass	Energy	Mass	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
2.30	28624.8	19489.8	18883.7	10545.2
2.40	27473.4	18894.4	18679.9	10430.2
2.50	25812.6	17919.6	18225.6	10174.1
2.60	23445.9	16406.6	17913.3	9999.6
2.70	21177.9	14934.0	17687.2	9873.3
2.80	20466.3	14544.8	17437.3	9733.2
2.90	19281.8	13762.0	17183.3	9591.1
3.00	18200.6	13047.6	16939.2	9454.7
3.10	17230.7	12400.6	16724.3	9335.1
3.20	16283.2	11760.8	16536.4	9230.8
3.30	15440.8	11192.7	16353.1	9129.0
3.40	14715.2	10705.1	16182.3	9034.3
3.50	14131.3	10316.6	16031.0	8950.7
3.60	13676.9	10015.2	15890.4	8873.1
3.70	13302.5	9764.8	15750.5	8795.7
3.80	12973.0	9542.3	15620.1	8723.8
3.90	12689.8	9349.7	15501.7	8658.6
4.00	12442.2	9179.4	15387.3	8595.7
4.20	12009.3	8874.3	15166.9	8474.6
5.20	10934.2	8003.4	14233.3	7966.4
5.40	10891.1	7938.5	15347.0	8599.8
5.60	10860.6	7880.3	15358.3	8603.5
5.80	10823.3	7819.4	15304.7	8578.2
6.00	10821.3	7783.8	15243.0	8547.0

Table 2.6.3.1-10
DEPS Break Blowdown M&E Release
(applicable for DEPS Minimum safeguards cases)

Time	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass	Energy	Mass	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
6.20	10835.3	7760.4	15117.2	8480.1
7.20	10712.4	7575.6	14512.7	8156.4
7.40	10729.7	7558.6	14377.6	8080.7
7.60	10785.4	7560.6	14241.6	8004.4
7.80	11221.6	7824.4	14118.5	7935.7
8.00	11039.3	7654.1	14070.5	7909.8
8.20	10520.4	7574.6	14008.7	7874.5
8.40	9390.7	7192.2	13806.2	7759.0
8.60	8956.0	6962.5	13624.6	7657.0
8.80	8994.3	6928.3	13478.5	7577.1
9.00	9018.5	6875.8	13353.8	7508.6
9.20	9007.9	6816.4	13179.4	7410.3
9.40	9020.8	6776.2	12997.6	7307.9
9.60	9038.6	6731.9	12863.0	7232.5
9.80	9050.7	6681.7	12712.7	7148.0
10.0	9056.9	6631.2	12545.1	7053.5
10.2	9045.4	6573.0	12404.4	6974.2
10.4	9012.0	6506.8	12263.6	6894.7
10.4	9011.8	6506.4	12262.7	6894.2
10.4	9011.5	6506.0	12261.9	6893.7
10.6	8960.6	6435.5	12115.2	6810.9
10.8	8885.8	6354.4	11979.2	6734.1
11.0	8792.0	6267.7	11847.4	6659.6
11.2	8679.9	6175.2	11713.7	6584.1

Table 2.6.3.1-10
DEPS Break Blowdown M&E Release
(applicable for DEPS Minimum safeguards cases)

	Break Path No. 1*		Break Path No. 2 Flow**	
Time	Mass	Energy	Mass	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
11.4	8554.5	6080.0	11587.8	6512.9
11.6	8419.0	5983.5	11463.7	6442.9
11.8	8275.2	5886.2	11342.8	6374.6
12.0	8129.5	5792.2	11223.7	6307.3
12.2	7984.9	5701.5	11106.5	6241.2
12.4	7836.7	5610.2	10991.7	6176.5
12.6	7691.1	5522.7	10879.1	6112.9
12.8	7549.1	5439.4	10765.8	6049.0
13.0	7409.0	5358.2	10656.4	5987.3
13.2	7271.5	5279.5	10547.4	5925.8
13.4	7137.0	5203.3	10438.4	5864.3
13.6	7005.8	5129.3	10331.8	5804.3
13.8	6874.0	5055.3	10228.6	5746.1
14.0	6749.6	4988.7	10122.6	5686.3
14.2	6627.2	4922.3	10016.2	5626.4
14.4	6509.0	4856.0	9914.8	5569.6
14.6	6392.1	4788.7	9797.1	5503.4
14.8	6271.5	4718.5	9677.6	5436.8
15.0	6137.5	4638.6	9537.3	5359.0
15.2	5998.5	4552.7	9402.8	5285.2
15.4	5863.8	4463.9	9271.8	5213.2
15.6	5741.5	4377.5	9147.0	5144.3
15.8	5635.1	4297.3	9030.3	5079.5
16.0	5542.2	4224.0	8923.5	5020.4

Table 2.6.3.1-10
DEPS Break Blowdown M&E Release
(applicable for DEPS Minimum safeguards cases)

Time	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass	Energy	Mass	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
16.2	5460.1	4157.1	8821.1	4963.9
16.4	5385.6	4096.4	8724.5	4911.2
16.6	5315.4	4041.1	8630.2	4860.7
16.8	5246.7	3989.9	8540.0	4810.0
17.0	5177.9	3942.1	8468.5	4757.8
17.2	5106.3	3896.4	8405.6	4697.4
17.4	5030.7	3852.3	8375.8	4641.4
17.6	4946.5	3807.2	8336.6	4568.7
17.8	4829.6	3745.6	8180.4	4423.7
18.0	4660.7	3657.6	8027.8	4270.9
18.2	4452.1	3547.8	7758.1	4053.9
18.4	4273.5	3454.3	7265.8	3729.6
18.6	4153.7	3399.3	7090.2	3590.1
18.8	4022.2	3387.8	6698.6	3355.6
19.0	3790.2	3379.4	6402.7	3167.5
19.2	3487.3	3352.5	6079.7	2973.0
19.4	3178.0	3308.0	5784.3	2798.2
19.6	2881.3	3238.3	5493.4	2632.1
19.8	2632.8	3132.3	5059.7	2398.0
20.0	2407.8	2944.5	4661.7	2150.5
20.2	2199.2	2712.8	4374.3	1947.8
20.4	2029.5	2513.8	4242.1	1825.3
20.6	1861.5	2312.7	4648.5	1944.2
20.8	1697.3	2114.8	5359.7	2207.5

Table 2.6.3.1-10
DEPS Break Blowdown M&E Release
(applicable for DEPS Minimum safeguards cases)

Time	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass	Energy	Mass	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
21.0	1551.9	1938.7	4900.1	2002.9
21.2	1448.6	1813.6	3822.5	1553.7
21.4	1360.4	1705.8	3294.6	1336.4
21.6	1273.1	1598.8	2658.1	1068.0
21.8	1180.3	1484.4	2394.1	910.7
22.0	1074.4	1353.1	2868.1	1023.7
22.2	983.8	1240.7	3759.1	1289.0
22.4	899.0	1135.2	4452.8	1491.1
22.6	809.9	1024.2	4384.9	1444.7
22.8	725.9	919.3	3948.3	1285.9
23.0	653.0	827.7	3552.1	1144.4
23.2	586.8	744.4	3252.3	1035.0
23.4	540.5	686.4	2996.8	940.1
23.6	488.9	621.0	2756.5	851.4
23.8	432.9	550.5	2496.6	758.7
24.0	354.1	450.5	2220.4	663.9
24.2	308.2	392.4	1984.4	584.1
24.4	316.1	402.8	1743.7	505.6
24.4	314.7	401.0	1721.1	498.3
24.6	206.0	262.5	1500.8	429.1
24.8	126.7	161.8	1250.0	352.8
25.0	53.9	69.0	985.6	275.1
25.2	0.0	0.0	682.1	188.9
25.4	0.0	0.0	411.4	113.6

Table 2.6.3.1-10
DEPS Break Blowdown M&E Release
(applicable for DEPS Minimum safeguards cases)

Time	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass	Energy	Mass	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
25.6	0.0	0.0	228.7	63.2
25.8	0.0	0.0	81.0	22.5
25.9	0.0	0.0	0.0	0.0

Notes:
*Path 1:M&E exiting from the steam generator side of the break.
**Path 2: M&E exiting from the broken loop reactor coolant pump side of the break.

Table 2.6.3.1-11
DEPS Break
Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1* Mass lbm/sec	Break Path No. 1* Energy Thousand btu/sec	Break Path No. 2 Flow** Mass lbm/sec	Break Path No. 2 Flow** Energy Thousand btu/sec
25.9		.0	.0	.0
26.4	.0	.0	.0	.0
26.6	.0	.0	.0	.0
26.7	.0	.0	.0	.0
26.8	.0	.0	.0	.0
26.9	.0	.0	.0	.0
27.0	76.7	90.1	.0	.0
27.1	26.3	30.9	.0	.0
27.2	21.2	24.9	.0	.0
27.3	26.5	31.2	.0	.0
27.4	34.5	40.6	.0	.0
27.5	38.9	45.7	.0	.0
27.6	43.3	50.8	.0	.0
27.7	47.3	55.6	.0	.0
27.8	51.2	60.2	.0	.0
27.9	54.8	64.5	.0	.0
28.0	58.3	68.6	.0	.0
28.1	61.7	72.5	.0	.0
28.2	64.9	76.3	.0	.0
28.3	68.0	79.9	.0	.0
28.4	71.0	83.5	.0	.0
28.5	73.9	86.9	.0	.0
28.6	76.7	90.2	.0	.0
28.7	79.5	93.4	.0	.0

Table 2.6.3.1-11
DEPS Break
Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
28.8	82.1	96.6	.0	.0
28.9	84.7	99.6	.0	.0
29.0	87.3	102.6	.0	.0
30.0	109.9	129.2	.0	.0
31.0	128.9	151.7	.0	.0
32.1	395.4	467.8	4466.8	611.9
32.7	438.5	519.4	4894.3	701.7
33.1	438.7	519.7	4896.2	705.3
34.1	432.5	512.2	4838.0	699.9
35.1	424.9	503.2	4765.4	691.8
36.1	417.2	493.9	4689.5	683.1
37.1	409.4	484.7	4613.1	674.1
37.3	407.9	482.8	4598.0	672.3
38.1	401.9	475.7	4537.8	665.1
39.1	394.6	467.0	4464.2	656.3
40.1	387.6	458.6	4392.7	647.7
41.1	380.9	450.5	4323.3	639.3
42.1	374.4	442.8	4256.1	631.2
43.1	368.2	435.3	4191.2	623.4
43.5	365.7	432.4	4165.8	620.3
44.1	362.2	428.2	4128.3	615.7
45.1	356.4	421.3	4067.6	608.4
46.2	382.1	452.0	4380.0	630.7
47.2	376.9	445.7	4326.2	624.0
48.2	371.8	439.7	4274.0	617.5

Table 2.6.3.1-11
DEPS Break
Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
49.2	367.0	433.9	4223.4	611.2
50.2	362.2	428.2	4174.3	605.2
50.5	360.9	426.6	4159.9	603.4
51.2	357.7	422.8	4126.7	599.2
52.2	359.2	424.4	299.3	200.8
53.2	394.9	467.2	314.8	223.5
54.2	386.4	457.1	311.0	218.2
55.2	377.0	445.8	306.7	212.3
56.2	367.8	434.9	302.5	206.6
57.2	358.7	424.0	298.4	201.0
57.7	354.5	419.0	296.6	198.4
58.2	350.6	414.3	294.8	196.0
59.2	343.0	405.3	291.4	191.3
60.2	335.7	396.6	288.1	186.8
61.2	328.8	388.3	285.0	182.5
62.2	322.1	380.3	282.0	178.5
63.2	315.6	372.7	279.2	174.6
64.2	309.5	365.3	276.4	170.8
65.2	303.6	358.3	273.8	167.3
66.2	297.9	351.5	271.3	163.9
67.2	292.4	345.0	268.9	160.6
68.2	287.2	338.8	266.6	157.5
69.2	282.2	332.8	264.4	154.5
70.2	277.3	327.1	262.3	151.6
71.2	272.7	321.6	260.3	148.8

Table 2.6.3.1-11
DEPS Break
Reflood M&E Release – Minimum SI

	Break Path No. 1*		Break Path No. 2 Flow**	
Time Seconds	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
72.2	268.2	316.3	258.3	146.2
73.2	263.9	311.2	256.5	143.7
74.2	259.8	306.3	254.7	141.3
75.2	255.9	301.6	253.0	139.0
75.7	254.0	299.3	252.2	137.9
76.2	252.1	297.1	251.4	136.8
77.2	248.4	292.8	249.8	134.7
78.2	245.0	288.6	248.4	132.6
79.2	241.6	284.6	246.9	130.7
80.2	238.4	280.8	245.6	128.9
81.2	235.3	277.2	244.3	127.1
82.2	232.3	273.6	243.0	125.4
83.2	229.5	270.3	241.9	123.8
84.2	226.8	267.0	240.7	122.2
85.2	224.2	263.9	239.6	120.7
86.2	221.7	261.0	238.6	119.3
87.2	219.3	258.1	237.6	118.0
89.2	214.8	252.8	235.8	115.5
91.2	210.7	248.0	234.1	113.2
93.2	207.0	243.6	232.6	111.1
95.2	203.6	239.5	231.3	109.2
97.2	200.5	235.9	230.0	107.5
99.2	197.7	232.6	228.9	105.9
99.4	197.4	232.3	228.8	105.8
101.2	195.3	229.7	227.9	104.6

Table 2.6.3.1-11
DEPS Break
Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
103.2	193.5	227.6	227.2	103.6
105.2	191.8	225.6	226.5	102.7
107.2	190.3	223.9	225.8	101.9
109.2	189.0	222.3	225.3	101.2
111.2	187.8	220.9	224.7	100.5
113.2	186.7	219.6	224.3	99.9
115.2	185.8	218.5	223.9	99.4
117.2	184.9	217.5	223.5	98.9
119.2	184.2	216.6	223.2	98.5
121.2	183.6	215.9	222.9	98.2
123.2	183.0	215.2	222.7	97.9
125.2	182.5	214.7	222.5	97.6
127.2	182.1	214.2	222.3	97.4
127.5	182.1	214.1	222.3	97.3
129.2	181.8	213.8	222.1	97.2
131.2	181.6	213.5	222.0	97.0
133.2	181.3	213.3	221.9	96.9
135.2	181.2	213.1	221.8	96.8
137.2	181.1	213.0	221.8	96.7
139.2	181.1	212.9	221.7	96.7
141.2	181.0	212.9	221.7	96.6
143.2	181.1	212.9	221.7	96.6
145.2	181.1	213.0	221.7	96.6
147.2	181.2	213.1	221.7	96.7
149.2	181.4	213.3	221.8	96.7

Table 2.6.3.1-11
DEPS Break
Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
151.2	181.5	213.4	221.8	96.8
153.2	181.7	213.6	221.9	96.8
155.2	181.8	213.8	221.9	96.9
157.2	182.0	214.0	222.0	97.0
158.1	182.1	214.2	222.0	97.0
159.2	182.2	214.3	222.0	97.1
161.2	182.5	214.6	222.1	97.2
163.2	182.7	214.9	222.2	97.3
165.2	183.0	215.2	222.3	97.4
167.2	183.3	215.5	222.4	97.5
169.2	183.5	215.8	222.5	97.6
171.2	183.8	216.2	222.6	97.8
173.2	184.2	216.6	222.7	97.9
175.2	184.6	217.0	222.9	98.1
177.2	185.6	218.2	223.6	98.6
179.2	186.6	219.4	225.0	99.2
181.2	187.7	220.8	226.8	99.9
183.2	188.9	222.2	229.1	100.6
185.2	190.1	223.6	231.6	101.3
187.2	191.2	224.9	234.3	102.1
189.2	192.3	226.2	237.1	102.8
190.3	192.9	226.9	238.6	103.2
191.2	193.3	227.3	239.9	103.5
193.2	194.1	228.4	242.7	104.1
195.2	194.9	229.2	245.5	104.6

Table 2.6.3.1-11
DEPS Break
Reflood M&E Release – Minimum SI

Time Seconds	Break Path No. 1*		Break Path No. 2 Flow**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
197.2	195.5	229.9	248.3	105.1
199.2	196.0	230.5	251.1	105.6
201.2	196.3	230.9	253.9	106.0
203.2	196.6	231.2	256.7	106.4
205.2	196.7	231.4	259.6	106.7
207.2	196.8	231.5	262.4	107.0
209.2	196.7	231.4	265.3	107.2
211.2	196.6	231.3	268.2	107.4
213.2	196.4	231.0	271.2	107.6
215.2	196.1	230.7	274.1	107.8
217.2	195.7	230.2	277.1	108.0
219.2	195.3	229.7	280.1	108.1
221.2	194.7	229.1	283.1	108.2
223.2	194.1	228.3	286.2	108.3
224.2	193.8	228.0	287.7	108.4

Notes:
*Path 1: M&E exiting from the steam generator side of the break.
**Path 2:M&E exiting from the broken loop reactor coolant pump side of the break.

Table 2.6.3.1-12
DEPS - Minimum Safety Injection Principal Parameters During Reflood

Time sec	Temp °F	Flooding Rate in/sec	Carry-over Fraction	Core Height ft	Down-Comer Height ft	Flow Fraction	Total	Injection Accumu lator	SI Spill	Enthalpy Btu/Lbm
							(Pounds mass per second)			
25.9	189.7	.000	.000	.00	.00	.250	.0	.0	.0	.00
26.7	186.8	22.951	.000	.67	1.56	.000	7818.2	7818.2	.0	89.66
26.9	185.3	25.174	.000	1.07	1.48	.000	7767.9	7767.9	.0	89.66
27.2	184.5	2.933	.119	1.33	2.15	.231	7655.1	7655.1	.0	89.66
27.3	184.5	2.951	.140	1.35	2.47	.252	7637.2	7637.2	.0	89.66
28.2	184.4	2.497	.310	1.50	5.31	.328	7420.7	7420.7	.0	89.66
29.0	184.3	2.417	.411	1.61	7.83	.344	7251.2	7251.2	.0	89.66
32.7	184.3	4.544	.640	2.01	16.12	.588	5967.0	5967.0	.0	89.66
34.1	184.3	4.236	.679	2.19	16.12	.587	5763.1	5763.1	.0	89.66
37.3	184.6	3.829	.716	2.50	16.12	.581	5398.6	5398.6	.0	89.66
43.5	186.3	3.402	.740	3.01	16.12	.568	4851.0	4851.0	.0	89.66
45.1	186.8	3.322	.743	3.12	16.12	.565	4732.4	4732.4	.0	89.66
46.2	187.2	3.474	.744	3.20	16.12	.578	5083.4	4547.3	.0	87.38
50.5	189.0	3.298	.749	3.51	16.12	.571	4819.6	4276.6	.0	87.22
51.2	189.3	3.273	.750	3.55	16.12	.570	4780.2	4236.2	.0	87.20
52.2	189.7	3.307	.752	3.62	16.07	.583	547.3	.0	.0	68.03
53.2	190.2	3.486	.752	3.69	15.86	.589	531.9	.0	.0	68.03

Table 2.6.3.1-12
DEPS - Minimum Safety Injection Principal Parameters During Reflood

Time sec	Temp °F	Flooding Rate in/sec	Carry-over Fraction	Core Height ft	Down-Comer Height ft	Flow Fraction	Total	Injection Accumu lator	SI Spill	Enthalpy Btu/Lbm
							(Pounds mass per second)			
57.7	192.9	3.156	.753	4.00	14.99	.583	544.1	.0	.0	68.03
66.2	199.1	2.703	.754	4.51	13.84	.571	560.6	.0	.0	68.03
75.7	207.2	2.354	.755	5.00	13.11	.559	572.9	.0	.0	68.03
87.2	217.2	2.077	.757	5.52	12.74	.545	582.5	.0	.0	68.03
99.4	226.1	1.899	.761	6.00	12.75	.535	589.2	.0	.0	68.03
113.2	234.5	1.808	.765	6.51	13.02	.529	591.0	.0	.0	68.03
127.5	241.9	1.762	.769	7.00	13.44	.526	591.7	.0	.0	68.03
143.2	248.8	1.741	.775	7.52	13.97	.526	591.9	.0	.0	68.04
158.1	254.5	1.736	.780	8.00	14.51	.526	591.8	.0	.0	68.03
161.2	255.6	1.736	.782	8.10	14.62	.527	591.8	.0	.0	68.03
175.2	260.2	1.738	.787	8.54	15.13	.528	591.5	.0	.0	68.04
190.3	264.5	1.773	.793	9.00	15.61	.537	590.2	.0	.0	68.03
197.2	266.3	1.778	.795	9.21	15.76	.541	589.8	.0	.0	68.03
207.2	268.7	1.766	.799	9.51	15.91	.546	589.5	.0	.0	68.04
224.2	272.4	1.711	.805	10.00	16.06	.551	590.0	.0	.0	68.04

Table 2.6.3.1-13
DEPS Break Mass Balance Minimum Safeguards

	Time (Seconds)	**.00**	**25.90**	**25.90+ε**	**224.20**
		Mass (Thousands lbm)			
Initial	In RCS and Accumulator	744.62	744.62	744.62	744.62
Added Mass	Pumped Injection	.00	.00	.00	104.33
	Total Added	.00	.00	.00	104.33
*** Total Available ***		744.62	744.62	744.62	848.94
Distribution	Reactor Coolant	517.02	54.32	81.05	142.19
	Accumulator	227.59	169.67	142.94	.00
	Total Contents	744.62	223.99	223.99	142.19
Effluent	Break Flow	.00	520.61	520.61	695.29
	ECCS Spill	.00	.00	.00	.00
	Total Effluent	.00	520.61	520.61	695.29
*** Total Accountable ***		744.62	744.60	744.60	837.47

* - +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

Table 2.6.3.1-14
DEPS Break Energy Balance Minimum Safeguards

	Time (Seconds)	**.00**	**25.90**	**25.90+ε**	**224.20**
		Energy (Millions btu)			
Initial Energy	In RCS, Accumulators and Steam Generators	851.30	851.30	851.30	851.30
Added Energy	Pumped Injection	.00	.00	.00	7.10
	Decay Heat	.00	8.57	8.57	33.18
	Heat from Secondary	.00	9.67	9.67	9.67
	Total Added	.00	18.24	18.24	49.95
*** Total Available ***		851.30	869.54	869.54	901.25
Distribution	Reactor Coolant	308.07	12.36	14.76	36.18
	Accumulator	20.41	15.21	12.82	.00
	Core Stored	24.79	13.19	13.19	4.67
	Primary Metal	153.93	146.66	146.66	119.44
	Secondary Metal	52.81	52.82	52.82	48.06
	Steam Generator	291.30	305.88	305.88	274.20
	Total Contents	851.30	546.13	546.13	482.55
Effluent	Break Flow	.00	322.82	322.82	407.69
	ECCS Spill	.00	.00	.00	.00
	Total Effluent	.00	322.82	322.82	407.69
*** Total Accountable ***		851.30	868.95	868.95	890.23

* - +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

Table 2.6.3.1-15
DEPS Break Blowdown M&E Release
(Applicable for DEPS Maximum Safeguards Cases)

Time Seconds	Break Path No. 1 Flow* Mass lbm/sec	Break Path No. 1 Flow* Energy Thousand btu/sec	Break Path No. 2 Flow** Mass lbm/sec	Break Path No. 2 Flow** Energy Thousand btu/sec
.00000	.0	.0	.0	.0
.00109	88647.9	49448.7	42509.5	23658.5
.101	41991.8	23439.1	21604.7	12011.1
.202	42476.9	23866.9	24069.2	13393.2
.301	43151.4	24463.3	24420.6	13601.0
.402	43943.3	25191.7	23732.2	13231.0
.502	44487.7	25814.7	22669.6	12648.1
.601	44445.0	26089.7	21801.9	12169.3
.702	43608.7	25870.7	21018.0	11734.4
.801	42303.6	25329.6	20398.8	11390.8
.901	40900.2	24694.3	19981.1	11161.5
1.00	39599.2	24089.6	19743.1	11031.2
1.10	38481.5	23577.0	19602.1	10954.3
1.20	37562.2	23175.7	19511.7	10904.7
1.30	36796.7	22864.0	19448.2	10869.4
1.40	36111.0	22601.6	19400.6	10842.4
1.50	35464.2	22366.7	19370.2	10824.8
1.60	34807.7	22130.6	19358.9	10817.8
1.70	34110.8	21878.5	19354.4	10814.5
1.80	33341.5	21589.3	19331.6	10800.8
1.90	32426.8	21207.1	19283.1	10772.5
2.00	31503.7	20814.3	19215.6	10733.5
2.10	30517.9	20373.4	19121.5	10679.8
2.20	29534.9	19922.1	19008.5	10615.7
2.30	28536.0	19446.9	18857.4	10530.3

Table 2.6.3.1-15
DEPS Break Blowdown M&E Release
(Applicable for DEPS Maximum Safeguards Cases)

Time Seconds	Break Path No. 1 Flow*		Break Path No. 2 Flow**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
2.40	27344.9	18823.5	18652.7	10414.8
2.50	25633.3	17810.0	18208.3	10164.2
2.60	23153.6	16214.4	17888.4	9985.5
2.70	21059.7	14866.2	17659.4	9857.5
2.80	20363.7	14482.5	17409.3	9717.3
2.90	19119.1	13654.9	17156.4	9575.8
3.00	18066.3	12960.4	16914.1	9440.6
3.10	17089.9	12307.2	16702.8	9323.0
3.20	16149.7	11672.5	16516.1	9219.4
3.30	15316.7	11110.8	16332.2	9117.3
3.40	14613.9	10639.6	16165.0	9024.6
3.50	14049.6	10264.8	16015.1	8941.7
3.60	13606.3	9970.5	15873.4	8863.5
3.70	13240.6	9725.7	15734.1	8786.5
3.80	12919.0	9508.2	15605.7	8715.7
3.90	12641.6	9319.4	15488.4	8651.1
4.00	12398.0	9151.4	15373.5	8587.9
4.20	11972.2	8850.6	15154.4	8467.6
4.40	11648.3	8612.3	14932.6	8346.0
4.60	11387.2	8408.4	14740.1	8240.9
4.80	11188.4	8243.6	14540.4	8132.0
5.00	11025.9	8099.4	14369.2	8039.3
5.20	10922.0	7993.9	14225.4	7962.0
5.40	10882.2	7931.2	15378.8	8616.9
5.60	10851.4	7872.7	15349.8	8598.6

Table 2.6.3.1-15
DEPS Break Blowdown M&E Release
(Applicable for DEPS Maximum Safeguards Cases)

Time Seconds	Break Path No. 1 Flow* Mass lbm/sec	Break Path No. 1 Flow* Energy Thousand btu/sec	Break Path No. 2 Flow** Mass lbm/sec	Break Path No. 2 Flow** Energy Thousand btu/sec
5.80	10815.3	7812.4	15305.2	8578.6
6.00	10815.8	7778.7	15235.9	8542.9
6.20	10828.8	7754.8	15109.4	8475.6
6.40	10812.4	7717.3	14974.8	8403.9
6.60	10773.3	7671.4	14839.8	8331.9
6.80	10730.6	7627.2	14704.9	8259.7
7.00	10710.3	7597.3	14617.8	8213.8
7.20	10701.5	7568.7	14506.8	8152.8
7.40	10720.6	7552.6	14371.2	8077.0
7.60	10778.2	7555.3	14235.8	8001.0
7.80	11213.7	7817.0	14113.7	7932.8
8.00	11030.6	7649.2	14069.0	7908.8
8.20	10491.4	7565.1	13999.8	7869.3
8.40	9365.9	7179.5	13797.7	7754.1
8.60	8952.2	6957.9	13617.7	7653.0
8.80	8993.0	6924.5	13472.2	7573.4
9.00	9014.9	6871.3	13347.5	7504.9
9.20	9004.5	6812.4	13172.3	7406.1
9.40	9017.5	6771.9	12990.8	7303.8
9.60	9035.2	6727.2	12855.8	7228.3
9.80	9047.0	6677.1	12705.5	7143.7
10.0	9052.9	6626.5	12537.9	7049.2
10.2	9040.2	6567.5	12397.2	6969.9
10.4	9006.1	6501.2	12256.7	6890.6
10.6	8954.0	6429.8	12107.9	6806.5

Table 2.6.3.1-15
DEPS Break Blowdown M&E Release
(Applicable for DEPS Maximum Safeguards Cases)

Time Seconds	Break Path No. 1 Flow*		Break Path No. 2 Flow**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
10.8	8878.7	6348.8	11973.1	6730.4
11.0	8783.3	6261.2	11840.4	6655.5
11.2	8671.4	6169.2	11707.6	6580.4
11.4	8545.1	6073.6	11580.9	6508.8
11.6	8409.2	5977.1	11457.5	6439.2
11.8	8265.6	5880.4	11335.4	6370.2
12.0	8119.3	5785.8	11216.5	6303.1
12.2	7972.8	5694.1	11100.4	6237.6
12.4	7826.5	5604.8	10984.1	6172.0
12.6	7679.9	5516.6	10871.6	6108.5
12.8	7538.8	5433.9	10760.4	6045.8
13.0	7397.9	5352.3	10648.0	5982.4
13.2	7260.5	5273.9	10540.5	5921.8
13.4	7125.4	5197.4	10430.6	5859.8
13.6	6994.6	5123.9	10323.9	5799.6
13.8	6862.1	5049.6	10221.3	5741.8
14.0	6738.6	4983.7	10113.9	5681.2
14.2	6616.0	4917.1	10008.8	5622.1
14.4	6498.1	4850.8	9906.3	5564.6
14.6	6381.8	4783.9	9788.7	5498.6
14.8	6259.9	4713.0	9667.6	5431.1
15.0	6126.0	4633.1	9527.3	5353.3
15.2	5986.8	4546.8	9393.5	5279.9
15.4	5851.4	4457.1	9261.0	5207.0
15.6	5730.7	4371.3	9137.7	5138.9

Table 2.6.3.1-15
DEPS Break Blowdown M&E Release
(Applicable for DEPS Maximum Safeguards Cases)

Time Seconds	Break Path No. 1 Flow*		Break Path No. 2 Flow**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
15.8	5624.9	4291.3	9021.0	5074.1
16.0	5532.6	4218.1	8914.5	5015.1
16.2	5450.9	4151.4	8812.1	4958.7
16.4	5376.9	4090.9	8715.5	4906.0
16.6	5306.9	4035.8	8620.4	4854.9
16.8	5238.7	3985.1	8533.9	4805.4
17.0	5169.7	3937.5	8461.4	4751.3
17.2	5097.5	3891.6	8402.4	4691.4
17.4	5021.6	3847.8	8372.4	4633.9
17.6	4936.0	3802.2	8332.6	4559.9
17.8	4815.1	3738.6	8167.5	4409.2
18.0	4641.9	3648.5	8014.6	4255.6
18.2	4432.6	3538.3	7725.7	4029.1
18.4	4256.9	3446.4	7220.8	3700.3
18.6	4143.7	3397.2	7067.1	3572.9
18.8	4007.4	3390.6	6667.3	3334.9
19.0	3761.9	3381.8	6368.5	3145.0
19.2	3453.4	3354.5	6047.1	2951.6
19.4	3137.9	3308.5	5746.2	2773.7
19.6	2842.4	3232.9	5454.0	2607.0
19.8	2584.8	3100.3	5001.1	2361.6
20.0	2370.0	2905.1	4623.2	2121.4
20.2	2168.5	2677.7	4337.3	1921.2
20.4	2004.2	2484.4	4242.3	1817.0
20.6	1834.5	2280.6	4787.1	1995.6

Table 2.6.3.1-15
DEPS Break Blowdown M&E Release
(Applicable for DEPS Maximum Safeguards Cases)

Time Seconds	Break Path No. 1 Flow* Mass lbm/sec	Break Path No. 1 Flow* Energy Thousand btu/sec	Break Path No. 2 Flow** Mass lbm/sec	Break Path No. 2 Flow** Energy Thousand btu/sec
20.8	1672.0	2084.3	5377.1	2211.2
21.0	1533.2	1916.5	4731.3	1931.0
21.2	1433.3	1795.3	3763.8	1528.6
21.4	1343.2	1684.9	3229.8	1308.9
21.6	1257.8	1580.1	2581.4	1034.3
21.8	1158.7	1457.5	2377.3	897.0
22.0	1060.1	1335.6	2941.4	1041.4
22.2	968.4	1221.7	3899.4	1328.8
22.4	883.7	1116.2	4563.8	1520.6
22.6	794.4	1004.9	4357.7	1430.5
22.8	713.4	903.7	3908.2	1269.2
23.0	638.9	810.1	3514.4	1129.4
23.2	574.5	729.0	3218.8	1022.0
23.4	533.5	677.7	2965.3	928.2
23.6	475.1	603.6	2724.8	839.8
23.8	420.2	534.3	2461.5	746.6
24.0	343.1	436.7	2181.9	651.3
24.2	307.4	391.6	1953.0	574.1
24.4	311.0	396.3	1718.2	497.7
24.6	196.7	250.7	1473.5	420.9
24.8	116.7	149.1	1225.5	345.7
25.0	46.3	59.4	952.0	265.7
25.2	.0	.0	638.7	177.0
25.4	.0	.0	412.1	113.9
25.6	.0	.0	242.4	67.0

Table 2.6.3.1-15
DEPS Break Blowdown M&E Release
(Applicable for DEPS Maximum Safeguards Cases)

Time Seconds	Break Path No. 1 Flow*		Break Path No. 2 Flow**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
25.8	.0	.0	72.8	20.2
26.0	.0	.0	.0	.0

Notes:
*Path 1: M&E exiting from the steam generator side of the break.
**Path 2: M&E exiting from the broken loop reactor coolant pump side of the break.

Table 2.6.3.1-16
DEPS Break
Reflood M&E Release – Maximum SI

Time Seconds	Break Path No.1*		Break Path No.2**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
26.0	0.0	0.0	0.0	0.0
26.5	0.0	0.0	0.0	0.0
26.7	0.0	0.0	.00	0.0
26.8	0.0	0.0	0.0	0.0
26.9	0.0	0.0	0.0	0.0
27.0	0.0	0.0	0.0	0.0
27.1	80.1	94.1	0.0	0.0
27.2	27.0	31.7	0.0	0.0
27.3	21.1	24.7	0.0	0.0
27.4	26.2	30.8	0.0	0.0
27.5	34.2	40.2	0.0	0.0
27.6	38.5	45.3	0.0	0.0
27.7	42.8	50.3	0.0	0.0
27.8	46.9	55.0	0.0	0.0
27.9	50.7	59.5	0.0	0.0
28.0	54.3	63.8	0.0	0.0
28.1	57.7	67.8	0.0	0.0
28.2	61.0	71.7	0.0	0.0
28.3	64.2	75.4	0.0	0.0
28.3	65.0	76.4	0.0	0.0
28.4	67.3	79.1	0.0	0.0
28.5	70.3	82.5	0.0	0.0
28.6	73.1	85.9	0.0	0.0
28.7	75.9	89.2	0.0	0.0
28.8	78.6	92.4	0.0	0.0

Table 2.6.3.1-16
DEPS Break
Reflood M&E Release – Maximum SI

Time Seconds	Break Path No.1*		Break Path No.2**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
28.9	81.3	95.5	0.0	0.0
29.0	83.8	98.5	0.0	0.0
29.1	86.3	101.5	0.0	0.0
30.1	108.7	127.8	0.0	0.0
31.1	127.6	150.0	0.0	0.0
32.1	395.9	468.2	4539.3	617.8
32.7	438.3	519.1	4962.1	706.8
33.1	438.5	519.3	4963.0	710.2
34.1	432.2	511.9	4903.4	704.7
35.1	424.7	502.8	4829.3	696.5
36.1	416.9	493.5	4751.7	687.6
37.1	409.1	484.2	4673.8	678.4
37.4	406.9	481.5	4650.5	675.7
38.1	401.6	475.2	4596.9	669.3
39.1	394.3	466.5	4521.7	660.3
40.1	387.3	458.1	4448.7	651.6
41.1	380.5	450.0	4378.0	643.1
42.1	374.0	442.2	4309.5	634.8
43.1	367.8	434.8	4243.2	626.9
43.7	364.1	430.5	4204.5	622.2
44.1	361.8	427.6	4179.2	619.1
45.1	356.0	420.8	4117.2	611.6
46.1	430.9	510.2	4988.9	678.7
47.1	425.7	504.0	4937.0	672.2
48.1	420.7	498.0	4886.9	665.9

Table 2.6.3.1-16
DEPS Break
Reflood M&E Release – Maximum SI

Time Seconds	Break Path No.1* Mass lbm/sec	Break Path No.1* Energy Thousand btu/sec	Break Path No.2** Mass lbm/sec	Break Path No.2** Energy Thousand btu/sec
49.1	415.9	492.2	4838.3	659.8
50.1	411.2	486.6	4791.0	653.8
50.2	410.7	486.1	4786.4	653.2
51.1	406.7	481.2	4745.2	648.0
52.1	402.3	476.0	4700.6	642.4
53.2	155.9	183.3	1178.2	231.9
54.2	155.2	182.5	1179.7	231.6
55.2	154.5	181.7	1181.5	231.4
56.2	153.8	180.9	1183.2	231.3
57.2	153.1	180.1	1185.0	231.1
58.2	152.5	179.3	1186.8	230.9
59.2	151.8	178.5	1188.5	230.8
60.2	151.1	177.7	1189.5	230.4
60.4	150.9	177.5	1189.9	230.4
61.2	150.7	177.2	1190.8	230.4
62.2	150.4	176.8	1191.8	230.3
63.2	150.1	176.5	1192.8	230.2
64.2	149.8	176.1	1193.8	230.1
65.2	149.5	175.8	1194.8	230.0
66.2	149.3	175.5	1195.8	229.9
67.2	149.0	175.1	1196.8	229.8
68.2	148.7	174.8	1197.8	229.7
69.2	148.4	174.5	1198.8	229.6
70.2	148.2	174.2	1199.7	229.5
71.2	147.9	173.9	1200.7	229.4

Table 2.6.3.1-16
DEPS Break
Reflood M&E Release – Maximum SI

Time Seconds	Break Path No.1*		Break Path No.2**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
72.2	147.6	173.5	1201.6	229.3
73.2	147.4	173.2	1202.6	229.2
74.2	147.1	172.9	1203.5	229.1
75.2	146.8	172.6	1204.5	229.0
76.2	146.6	172.3	1205.4	228.9
77.2	146.3	172.0	1206.4	228.8
78.2	146.1	171.7	1207.3	228.7
79.2	145.8	171.4	1208.2	228.6
80.2	145.6	171.1	1209.2	228.5
81.2	145.3	170.8	1210.1	228.4
82.2	145.1	170.5	1211.0	228.3
83.2	144.8	170.2	1211.9	228.2
84.2	144.6	169.9	1212.9	228.1
85.2	144.3	169.6	1213.8	228.0
85.9	144.2	169.4	1214.4	227.9
86.2	144.1	169.3	1214.7	227.9
87.2	143.9	169.1	1215.6	227.8
89.2	143.4	168.5	1217.5	227.6
91.2	142.9	167.9	1219.3	227.4
93.2	142.4	167.4	1221.1	227.2
95.2	142.0	166.8	1223.0	227.0
97.2	141.5	166.3	1224.8	226.8
99.2	141.1	165.7	1226.6	226.6
101.2	140.7	165.3	1228.1	226.4
103.2	140.4	164.9	1229.1	226.2

Table 2.6.3.1-16
DEPS Break
Reflood M&E Release – Maximum SI

Time Seconds	Break Path No.1* Mass lbm/sec	Break Path No.1* Energy Thousand btu/sec	Break Path No.2** Mass lbm/sec	Break Path No.2** Energy Thousand btu/sec
105.2	140.1	164.6	1230.2	226.1
107.2	139.8	164.2	1231.3	225.9
109.2	139.5	163.8	1232.3	225.7
111.2	139.2	163.5	1233.3	225.5
113.2	138.9	163.1	1234.4	225.3
114.1	138.7	163.0	1234.8	225.2
115.2	138.6	162.8	1235.4	225.1
117.2	138.3	162.5	1236.4	224.9
119.2	138.0	162.1	1237.4	224.8
121.2	137.7	161.8	1238.4	224.6
123.2	137.4	161.4	1239.4	224.4
125.2	137.1	161.1	1240.4	224.2
127.2	136.8	160.8	1241.4	224.0
129.2	136.6	160.4	1242.3	223.8
131.2	136.3	160.1	1243.3	223.6
133.2	136.0	159.8	1244.3	223.4
135.2	135.7	159.4	1245.2	223.2
137.2	135.5	159.1	1246.2	223.0
139.2	135.2	158.8	1247.2	222.8
141.2	134.9	158.5	1248.1	222.6
143.2	134.6	158.2	1249.1	222.4
145.2	134.4	157.8	1250.0	222.1
145.3	134.4	157.8	1250.1	222.1
147.2	134.1	157.5	1250.9	221.9
149.2	133.8	157.2	1251.9	221.7

Table 2.6.3.1-16
DEPS Break
Reflood M&E Release – Maximum SI

Time Seconds	Break Path No.1*		Break Path No.2**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
151.2	133.6	156.9	1252.8	221.5
153.2	133.3	156.6	1253.8	221.3
155.2	133.0	156.3	1254.7	221.1
157.2	132.8	156.0	1255.6	220.9
159.2	132.5	155.6	1256.6	220.7
161.2	132.2	155.3	1257.5	220.4
163.2	132.0	155.0	1258.4	220.2
165.2	131.7	154.7	1259.3	220.0
167.2	131.4	154.4	1260.3	219.8
169.2	131.2	154.1	1261.2	219.6
171.2	130.9	153.8	1262.1	219.3
173.2	130.7	153.5	1263.0	219.1
175.2	130.4	153.2	1264.0	218.9
177.2	130.2	152.9	1264.9	218.7
179.2	129.9	152.6	1265.8	218.5
180.0	129.8	152.5	1266.2	218.4
181.2	129.7	152.3	1266.7	218.2
183.2	129.4	152.0	1267.6	218.0
185.2	129.1	151.7	1268.5	217.8
187.2	128.9	151.4	1269.5	217.6
189.2	128.7	151.1	1270.4	217.3
191.2	128.4	150.8	1271.3	217.1
193.2	128.2	150.5	1272.2	216.9
195.2	127.9	150.2	1273.1	216.7
197.2	127.7	150.0	1274.0	216.4

Table 2.6.3.1-16
DEPS Break
Reflood M&E Release – Maximum SI

Time Seconds	Break Path No.1*		Break Path No.2**	
	Mass lbm/sec	Energy Thousand btu/sec	Mass lbm/sec	Energy Thousand btu/sec
199.2	127.4	149.7	1274.9	216.2
201.2	127.2	149.4	1275.9	216.0
203.2	126.9	149.1	1276.9	215.7
205.2	126.7	148.8	1278.0	215.5
207.2	126.4	148.5	1279.0	215.3
209.2	126.1	148.2	1280.1	215.1
211.2	125.9	147.9	1281.2	214.8
213.2	125.6	147.6	1282.2	214.6
215.2	125.4	147.3	1283.3	214.4
217.2	125.1	147.0	1284.3	214.1
219.2	124.9	146.7	1285.4	213.9
219.5	124.9	146.6	1285.6	213.9
221.2	124.6	146.4	1286.5	213.7
223.2	124.4	146.1	1287.5	213.5
225.2	124.2	145.8	1288.6	213.3
227.2	123.9	145.5	1289.7	213.0
229.2	123.7	145.3	1290.8	212.8
231.2	123.5	145.0	1291.9	212.6
233.2	123.2	144.7	1293.0	212.4
235.2	123.0	144.4	1294.1	212.2
237.2	122.8	144.2	1295.2	212.0
239.2	122.6	143.9	1296.3	211.8
241.2	122.3	143.6	1297.4	211.6
243.2	122.1	143.4	1298.6	211.4
245.2	121.9	143.1	1299.7	211.2

Table 2.6.3.1-16
DEPS Break
Reflood M&E Release – Maximum SI

Time Seconds	Break Path No.1* Mass lbm/sec	Break Path No.1* Energy Thousand btu/sec	Break Path No.2** Mass lbm/sec	Break Path No.2** Energy Thousand btu/sec
247.2	121.7	142.9	1300.8	211.0
249.2	121.5	142.6	1302.0	210.8
251.2	121.3	142.4	1303.2	210.6
253.2	121.1	142.2	1304.4	210.5
255.2	120.9	141.9	1305.6	210.3
257.2	120.7	141.7	1306.8	210.1
259.2	120.5	141.5	1308.0	210.0
261.2	120.3	141.3	1309.3	209.8
263.2	120.1	141.1	1310.5	209.7
265.2	120.0	140.8	1311.8	209.5
267.2	119.8	140.6	1313.1	209.4
268.0	119.7	140.6	1313.7	209.3

Notes:
*Path 1: M&E exiting from the steam generator side of the break.
**Path 2: M&E exiting from the broken loop reactor coolant pump side of the break.

Table 2.6.3.1-17
DEPS - Maximum Safety Injection Principal Parameters During Reflood

Time	Flooding		Carryover Fraction	Core Height	Downcomer Height	Flow Fraction	Injection			
	Temp	Rate					Total	Accumulator	Spill	Enthalpy
Seconds	Degree F	In/sec	(--)	Ft	Ft	(--)	(Pounds Mass Per Second)			BTU/LBM
26.0	192.8	0.000	0.000	0.00	0.00	0.250	0.0	0.0	0.0	0.00
26.8	189.8	23.156	0.000	0.67	1.58	0.000	7909.7	7909.7	0.0	89.66
27.0	188.1	25.398	0.000	1.08	1.50	0.000	7858.2	7858.2	0.0	89.66
27.3	187.3	2.922	0.117	1.32	2.17	0.234	7745.8	7745.8	0.0	89.66
27.4	187.3	2.936	0.138	1.35	2.49	0.253	7727.5	7727.5	0.0	89.66
28.3	187.1	2.472	0.312	1.50	5.44	0.329	7500.5	7500.5	0.0	89.66
29.1	187.1	2.395	0.409	1.60	7.92	0.345	7332.9	7332.9	0.0	89.66
32.7	186.9	4.544	0.638	2.00	16.12	0.589	6036.5	6036.5	0.0	89.66
34.1	186.8	4.227	0.678	2.18	16.12	0.588	5828.8	5828.8	0.0	89.66
37.4	187.0	3.805	0.717	2.50	16.12	0.582	5446.8	5446.8	0.0	89.66
43.7	188.3	3.375	0.741	3.01	16.12	0.569	4884.6	4884.6	0.0	89.66
45.1	188.8	3.305	0.743	3.11	16.12	0.567	4779.5	4779.5	0.0	89.66
46.1	189.1	3.775	0.745	3.18	16.12	0.599	5769.9	4407.2	0.0	84.55
50.2	190.6	3.603	0.750	3.50	16.12	0.594	5524.3	4149.5	0.0	84.28
53.2	191.7	2.014	0.744	3.70	16.12	0.407	1492.9	0.0	0.0	68.03
60.4	194.9	1.956	0.746	4.00	16.12	0.405	1494.8	0.0	0.0	68.03
73.2	202.4	1.890	0.751	4.52	16.12	0.407	1497.3	0.0	0.0	68.03

Table 2.6.3.1-17
DEPS - Maximum Safety Injection Principal Parameters During Reflood

Time	Flooding		Carryover Fraction	Core Height	Downcomer Height	Flow Fraction	Injection			
	Temp	Rate					Total	Accumulator	Spill	Enthalpy
Seconds	Degree F	In/sec	(--)	Ft	Ft	(--)	(Pounds Mass Per Second)			BTU/LBM
85.9	210.9	1.829	0.755	5.00	16.12	0.409	1499.8	0.0	0.0	68.03
101.2	221.6	1.759	0.760	5.56	16.12	0.412	1502.6	0.0	0.0	68.03
114.1	229.6	1.717	0.764	6.00	16.12	0.414	1502.5	0.0	0.0	68.04
131.2	238.7	1.663	0.770	6.56	16.12	0.417	1502.5	0.0	0.0	68.03
145.3	245.0	1.620	0.774	7.00	16.12	0.419	1502.5	0.0	0.0	68.03
163.2	251.9	1.567	0.780	7.53	16.12	0.423	1502.4	0.0	0.0	68.03
180.0	257.4	1.518	0.785	8.00	16.12	0.426	1502.4	0.0	0.0	68.03
199.2	262.7	1.463	0.792	8.51	16.12	0.431	1502.4	0.0	0.0	68.04
219.5	267.4	1.402	0.801	9.00	16.12	0.435	1503.0	0.0	0.0	68.03
243.2	272.0	1.332	0.813	9.52	16.12	0.441	1503.8	0.0	0.0	68.03
268.0	275.9	1.258	0.832	10.00	16.12	0.448	1504.5	0.0	0.0	68.03

Table 2.6.3.1-18
DEPS Break Mass Balance Maximum Safeguards

	Time (seconds)	**0.00**	**26.00**	**26.00+ε**	**268.00**
		Mass Thousand (lbm)			
Initial	In RCS and ACC	743.78	743.78	743.78	743.78
Added Mass	Pumped Injection	.00	.00	.00	333.47
	Total Added	.00	.00	.00	333.47
*** Total Available ***		743.78	743.78	743.78	1077.26
Distribution	Reactor Coolant	516.19	55.46	79.20	142.16
	Accumulator	227.59	168.54	144.79	.00
	Total Contents	743.78	224.00	224.00	142.16
Effluent	Break Flow	.00	519.77	519.77	923.64
	ECCS Spill	.00	.00	.00	.00
	Total Effluent	.00	519.77	519.77	923.64
*** Total Accountable ***		743.78	743.77	743.77	1065.80

+ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

Table 2.6.3.1-19
DEPS Break Energy Balance Maximum Safeguards

	Time(Seconds)	**.00**	**26.00**	**26.00+ε**	**268.00**
		Energy (Million btu)			
Initial Energy	In RCS, Accumulator & Steam Generator	850.76	850.76	850.76	850.76
Added Energy	Pumped Injection	.00	.00	.00	22.69
	Decay Heat	.00	8.58	8.58	37.83
	Heat From Secondary	.00	9.68	9.68	9.68
	Total Added	.00	18.26	18.26	70.19
*** Total Available ***		850.76	869.01	869.01	920.95
Distribution	Reactor Coolant	307.53	12.48	14.61	36.34
	Core Stored	24.79	13.23	13.23	4.68
	Primary Metal	153.93	146.64	146.64	116.46
	Secondary Metal	52.81	52.82	52.82	48.50
	Steam Generator	291.30	305.87	305.87	276.39
	Total Contents	850.76	546.15	546.15	482.37
Effluent	Break Flow	.00	322.27	322.27	427.52
	ECCS Spill	.00	.00	.00	.00
	Total Effluent	.00	322.27	322.27	427.52
*** Total Accountable ***		850.76	868.43	868.43	909.89

+ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

Table 2.6.3.1-20 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
	Mass	Energy	Mass	Energy
Seconds	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
0.000	0.0	0.0	0.0	0.0
0.0011	65291.2	36513.2	24094.0	13409.6
0.0024	41869.5	23332.2	25423.0	14148.6
0.0031	31254.1	17401.9	25314.5	14087.8
0.101	36764.7	20531.9	19937.9	11083.8
0.201	37127.3	20834.7	21834.0	12149.9
0.302	36391.2	20552.4	22392.3	12469.9
0.401	35618.1	20267.9	22137.1	12338.8
0.502	34575.8	19841.9	21428.1	11952.8
0.602	33368.1	19316.8	20763.7	11589.2
0.702	32079.4	18724.3	20308.4	11339.9
0.802	30582.5	17980.2	19967.1	11152.5
0.901	29143.0	17236.7	19676.6	10992.9
1.00	28419.3	16893.9	19464.9	10876.2
1.10	28461.5	16989.8	19304.5	10787.8
1.20	28424.3	17030.6	19195.2	10727.6
1.30	28376.3	17060.4	19115.0	10683.2
1.40	28327.7	17087.1	19054.2	10649.2
1.50	28259.7	17100.5	19017.0	10628.1
1.60	28154.2	17090.2	19011.6	10624.7
1.70	28012.0	17057.2	19031.4	10635.6
1.80	27847.0	17010.4	19054.0	10648.0
1.90	27655.9	16950.9	19063.2	10652.9
2.00	27418.8	16867.0	19067.6	10654.9

Table 2.6.3.1-20 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
	Mass	Energy	Mass	Energy
Seconds	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
2.10	27123.7	16750.6	19077.8	10660.3
2.20	26775.8	16608.5	19068.8	10655.1
2.30	26387.9	16449.8	19029.3	10632.7
2.40	25940.7	16263.4	18962.4	10595.0
2.50	25420.9	16038.8	18864.0	10539.6
2.60	24835.0	15781.2	18629.8	10407.9
2.70	24192.0	15494.4	18462.1	10314.2
2.80	23476.7	15165.7	18312.0	10230.3
2.90	22748.3	14829.9	18155.6	10142.8
3.00	22012.2	14488.4	17978.6	10043.8
3.10	21197.2	14090.4	17781.3	9933.4
3.20	20330.8	13645.0	17578.3	9820.0
3.30	19311.2	13082.3	17389.8	9714.8
3.40	18224.7	12462.0	17208.1	9613.6
3.50	17179.1	11855.8	17015.3	9506.1
3.60	16205.8	11282.5	16825.1	9400.2
3.70	15349.1	10773.1	16648.5	9302.1
3.80	14631.2	10343.5	16479.7	9208.4
3.90	14024.8	9976.2	16309.4	9113.8
4.00	13511.5	9661.0	16145.9	9023.2
4.20	12708.2	9156.9	15843.6	8855.9
4.40	12074.3	8745.1	15563.2	8701.1
4.60	11580.2	8415.8	15310.6	8562.0
4.80	11188.7	8145.9	15081.6	8436.4

Table 2.6.3.1-20 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
	Mass	Energy	Mass	Energy
Seconds	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
5.00	10884.8	7927.4	14865.5	8318.1
5.20	10640.1	7743.3	14673.7	8213.7
5.40	10444.0	7587.8	14485.7	8111.5
5.60	10288.6	7457.1	14325.3	8025.1
5.80	10173.9	7351.8	14175.2	7944.5
6.00	10133.9	7296.1	14051.8	7879.3
6.20	10121.8	7255.2	14792.8	8305.7
6.40	10102.7	7208.6	14795.6	8307.0
6.60	10098.2	7173.2	14849.1	8342.8
6.80	10126.5	7159.9	14767.7	8300.3
7.00	10161.9	7151.3	14644.2	8235.4
7.20	10170.4	7128.1	14515.0	8167.3
7.40	10152.8	7093.1	14381.7	8097.1
7.60	10122.0	7053.6	14245.5	8025.0
7.80	10083.5	7012.2	14127.3	7962.5
8.00	10054.9	6980.4	14056.4	7925.9
8.20	10288.1	7133.8	13965.4	7875.9
8.40	10127.1	6994.1	13905.8	7842.9
8.60	9965.3	6975.6	13847.4	7809.5
8.80	9169.0	6749.0	13719.7	7736.1
9.00	8229.0	6375.3	13594.9	7665.5
9.20	7866.7	6183.2	13473.6	7599.3
9.40	7824.1	6114.2	13363.0	7539.1
9.60	7854.6	6079.2	13216.2	7457.1

Table 2.6.3.1-20 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
	Mass	Energy	Mass	Energy
Seconds	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
9.80	7897.6	6054.2	13054.9	7366.7
10.0	7936.4	6024.4	12921.1	7292.4
10.2	7980.0	5995.8	12776.2	7210.9
10.4	8033.7	5972.8	12617.6	7121.3
10.4	8034.1	5972.6	12616.7	7120.8
10.4	8034.3	5972.5	12616.0	7120.5
10.6	8080.4	5945.5	12484.7	7046.5
10.8	8113.0	5912.8	12350.4	6970.8
11.0	8132.0	5877.3	12209.6	6891.1
11.2	8130.3	5834.4	12082.3	6819.2
11.4	8105.1	5782.1	11956.2	6748.0
11.6	8059.0	5723.0	11831.8	6677.7
11.8	7994.6	5658.8	11711.9	6610.0
12.0	7914.6	5590.3	11595.3	6544.2
12.2	7820.7	5518.0	11480.8	6479.7
12.4	7717.5	5444.4	11367.7	6416.0
12.6	7607.1	5370.0	11257.8	6354.2
12.8	7491.8	5295.5	11149.0	6293.1
13.0	7372.9	5221.3	11041.1	6232.5
13.2	7252.5	5148.0	10934.0	6172.5
13.4	7130.5	5075.0	10828.6	6113.5
13.6	7010.0	5004.3	10724.0	6055.0
13.8	6890.1	4935.1	10620.1	5996.8
14.0	6770.1	4866.8	10517.8	5939.7

Table 2.6.3.1-20 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
	Mass	Energy	Mass	Energy
Seconds	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
14.2	6651.8	4800.2	10415.2	5882.4
14.4	6535.5	4735.3	10314.0	5825.9
14.6	6421.4	4671.9	10213.2	5769.8
14.8	6309.0	4609.6	10113.3	5714.2
15.0	6200.8	4550.3	10012.8	5658.4
15.2	6092.5	4490.4	9914.9	5604.3
15.4	5985.8	4431.6	9814.5	5548.8
15.6	5879.2	4373.6	9703.2	5487.4
15.8	5762.9	4308.6	9578.2	5419.1
16.0	5639.6	4237.1	9444.2	5346.7
16.2	5515.9	4162.3	9305.3	5272.2
16.4	5396.7	4087.0	9180.2	5205.2
16.6	5289.6	4015.6	9058.2	5139.1
16.8	5196.8	3950.3	8949.8	5080.3
17.0	5115.4	3890.1	8843.7	5022.8
17.2	5043.9	3835.3	8744.4	4969.7
17.4	4979.2	3785.3	8646.9	4918.4
17.6	4916.9	3738.3	8551.1	4869.0
17.8	4856.0	3694.4	8456.5	4821.4
18.0	4794.2	3652.2	8359.8	4773.8
18.2	4724.3	3606.9	8137.4	4653.4
18.4	4630.3	3549.1	7994.3	4572.9
18.6	4504.5	3475.6	7778.4	4421.4
18.8	4354.2	3389.6	7735.6	4338.4

Table 2.6.3.1-20 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
	Mass	Energy	Mass	Energy
Seconds	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
19.0	4184.0	3292.1	7687.8	4226.5
19.2	4010.3	3191.8	7655.8	4111.7
19.4	3841.2	3090.4	7542.8	3959.2
19.6	3698.7	3002.9	7309.2	3756.7
19.8	3590.1	2928.7	7056.2	3573.4
20.0	3507.2	2873.0	6808.1	3413.6
20.2	3405.1	2837.6	6555.7	3258.9
20.4	3228.9	2793.3	6305.7	3112.0
20.6	2990.3	2733.7	6061.7	2977.8
20.8	2733.0	2666.1	5824.6	2858.6
21.0	2477.4	2593.0	5571.2	2744.2
21.2	2236.2	2513.2	5103.9	2506.4
21.4	2014.5	2397.7	4817.0	2302.3
21.6	1865.9	2283.6	4582.0	2109.7
21.8	1729.7	2134.1	4558.1	2017.7
22.0	1614.1	1999.6	4501.5	1932.1
22.2	1506.3	1871.6	4225.8	1771.2
22.4	1407.8	1753.8	3889.9	1596.3
22.6	1312.8	1639.1	3647.2	1465.1
22.8	1225.7	1533.6	3558.4	1399.9
23.0	1139.8	1428.9	3591.1	1386.4
23.2	1058.8	1329.9	3568.4	1355.5
23.4	982.6	1236.3	3498.6	1307.3
23.6	906.9	1142.7	3517.8	1289.1

Table 2.6.3.1-20 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
	Mass	Energy	Mass	Energy
Seconds	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
23.8	835.7	1054.7	3509.3	1257.9
24.0	770.8	974.2	3438.5	1205.5
24.2	709.5	897.9	3378.5	1159.0
24.4	652.6	826.9	3368.2	1129.4
24.6	602.2	764.1	3216.1	1054.6
24.8	556.0	706.2	3023.6	971.2
25.0	523.5	665.8	2816.6	886.4
25.2	486.8	619.4	2610.5	804.7
25.4	439.9	560.6	2382.4	719.7
25.6	387.8	494.2	2139.4	633.8
25.8	337.5	430.7	1879.9	546.9
26.0	309.5	395.6	1616.9	462.8
26.2	224.2	286.3	1345.0	379.5
26.4	159.8	204.5	1168.5	325.9
26.6	96.9	124.2	904.0	249.8
26.8	33.2	42.7	673.8	185.2
27.0	0.0	0.0	501.1	137.4
27.2	0.0	0.0	364.9	100.0
27.4	0.0	0.0	298.3	81.8
27.6	0.0	0.0	280.1	76.9
27.8	0.0	0.0	226.9	62.5
28.0	0.0	0.0	123.7	34.2
28.2	0.0	0.0	0.0	0.0

* Mass and energy exiting the SG side of the break
** Mass and energy exiting the pump side of the break

Table 2.6.3.1-21 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Reflood Mass and Energy Releases

	Break Path No.1*		Break Path No.2**	
Time	**Flow**	**Thousand**	**Flow**	**Thousand**
Seconds	**Lbm/sec**	**btu/sec**	**lbm/sec**	**btu/sec**
28.2	.0	.0	.0	.0
28.7	.0	.0	.0	.0
28.9	.0	.0	.0	.0
29.0	.0	.0	.0	.0
29.1	.0	.0	.0	.0
29.2	.0	.0	.0	.0
29.3	78.2	91.9	.0	.0
29.4	27.7	32.6	.0	.0
29.5	20.8	24.4	.0	.0
29.6	25.7	30.2	.0	.0
29.7	33.8	39.7	.0	.0
29.8	38.1	44.8	.0	.0
29.9	42.4	49.9	.0	.0
30.0	46.5	54.6	.0	.0
30.1	50.3	59.1	.0	.0
30.2	53.9	63.3	.0	.0
30.3	57.4	67.4	.0	.0
30.4	60.7	71.3	.0	.0
30.5	63.8	75.0	.0	.0
30.5	64.6	75.9	.0	.0
30.6	66.9	78.6	.0	.0
30.7	69.9	82.1	.0	.0
30.8	72.7	85.4	.0	.0
30.9	75.5	88.7	.0	.0
31.0	78.2	91.9	.0	.0

Table 2.6.3.1-21 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Reflood Mass and Energy Releases

	Break Path No.1*		Break Path No.2**	
Time	Flow	Thousand	Flow	Thousand
Seconds	Lbm/sec	btu/sec	lbm/sec	btu/sec
31.1	80.8	95.0	.0	.0
31.2	83.4	98.0	.0	.0
31.3	85.9	100.9	.0	.0
32.3	108.1	127.0	.0	.0
33.3	126.7	149.0	.0	.0
34.4	393.5	465.4	4524.4	616.4
35.0	434.9	515.0	4941.6	703.9
35.4	435.0	515.1	4944.0	707.4
36.4	428.6	507.4	4888.7	702.1
37.4	420.9	498.2	4819.0	694.2
38.4	413.0	488.8	4745.9	685.5
39.4	405.2	479.4	4672.4	676.7
39.8	402.1	475.7	4643.2	673.1
40.4	397.6	470.3	4599.9	667.8
41.4	390.2	461.4	4529.2	659.1
42.4	383.1	452.9	4460.6	650.6
43.4	376.2	444.7	4394.2	642.4
44.4	369.6	436.9	4330.1	634.4
45.4	363.3	429.3	4268.2	626.6
46.0	390.9	462.3	4604.1	651.9
46.4	388.6	459.5	4581.7	649.0
47.4	382.8	452.6	4527.5	642.1
48.4	377.3	446.0	4475.2	635.3
49.4	371.9	439.6	4424.7	628.8
50.4	366.9	433.5	4375.2	622.4

Table 2.6.3.1-21 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Reflood Mass and Energy Releases

	Break Path No.1*		Break Path No.2**	
Time	Flow	Thousand	Flow	Thousand
Seconds	Lbm/sec	btu/sec	lbm/sec	btu/sec
51.4	362.1	427.8	4323.7	616.1
52.4	357.5	422.3	4273.8	609.9
53.1	354.4	418.6	4239.7	605.7
53.4	353.1	417.1	4225.4	604.0
54.4	360.3	425.5	300.4	200.7
55.4	382.7	452.4	310.0	215.0
56.4	374.5	442.7	306.3	210.0
57.4	365.7	432.2	302.4	204.5
58.4	357.3	422.1	298.6	199.3
59.4	349.1	412.3	294.9	194.2
60.4	341.2	402.9	291.4	189.4
60.7	339.1	400.3	290.5	188.1
61.4	334.2	394.5	288.3	185.1
62.4	327.5	386.6	285.3	181.1
63.4	321.1	379.0	282.5	177.2
64.4	315.0	371.7	279.8	173.5
65.4	309.1	364.7	277.2	169.9
66.4	303.5	358.0	274.7	166.5
67.4	298.1	351.6	272.3	163.3
68.4	293.0	345.5	270.1	160.2
69.4	288.0	339.6	267.9	157.3
70.4	283.3	333.9	265.8	154.5
71.4	278.7	328.5	263.8	151.8
72.4	274.3	323.3	261.9	149.2
73.4	270.1	318.3	260.1	146.7

Table 2.6.3.1-21 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Reflood Mass and Energy Releases

	Break Path No.1*		Break Path No.2**	
Time	Flow	Thousand	Flow	Thousand
Seconds	Lbm/sec	btu/sec	lbm/sec	btu/sec
74.4	266.1	313.5	258.4	144.4
75.4	262.2	308.9	256.7	142.1
76.4	258.5	304.5	255.1	139.9
77.4	254.9	300.3	253.6	137.9
78.4	251.5	296.2	252.1	135.9
79.4	248.2	292.3	250.7	134.0
79.6	247.6	291.6	250.4	133.6
80.4	245.1	288.6	249.4	132.2
81.4	242.1	285.0	248.1	130.4
82.4	239.2	281.6	246.8	128.8
83.4	236.4	278.3	245.7	127.2
84.4	233.7	275.1	244.5	125.6
85.4	231.1	272.0	243.5	124.2
86.4	228.7	269.1	242.4	122.8
87.4	226.3	266.3	241.4	121.5
88.4	224.1	263.7	240.5	120.2
89.4	221.9	261.1	239.6	119.0
91.4	217.8	256.3	237.9	116.7
93.4	214.1	251.9	236.4	114.6
95.4	210.8	247.9	235.0	112.7
97.4	207.7	244.3	233.7	111.1
99.4	205.0	241.1	232.5	109.5
101.4	202.5	238.2	231.5	108.2
103.4	200.3	235.6	230.5	107.0
104.0	199.7	234.9	230.3	106.6

Table 2.6.3.1-21 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Reflood Mass and Energy Releases

	Break Path No.1*		Break Path No.2**	
Time	Flow	Thousand	Flow	Thousand
Seconds	Lbm/sec	btu/sec	lbm/sec	btu/sec
105.4	198.4	233.2	229.7	105.9
107.4	196.6	231.1	229.0	104.9
109.4	194.9	229.2	228.3	104.0
111.4	193.5	227.5	227.7	103.2
113.4	192.2	225.9	227.1	102.5
115.4	191.0	224.5	226.6	101.8
117.4	189.9	223.3	226.2	101.3
119.4	189.0	222.2	225.8	100.7
121.4	188.2	221.2	225.4	100.3
123.4	187.5	220.4	225.1	99.9
125.4	186.9	219.6	224.9	99.5
127.4	186.3	219.0	224.6	99.2
129.4	185.9	218.5	224.4	99.0
131.4	185.5	218.0	224.3	98.7
132.6	185.3	217.8	224.2	98.6
133.4	185.2	217.7	224.1	98.6
135.4	185.0	217.4	224.0	98.4
137.4	184.8	217.2	223.9	98.3
139.4	184.7	217.0	223.9	98.2
141.4	184.6	217.0	223.8	98.1
143.4	184.6	216.9	223.8	98.1
145.4	184.6	217.0	223.8	98.1
147.4	184.7	217.0	223.8	98.1
149.4	184.8	217.1	223.9	98.1
151.4	184.9	217.3	223.9	98.2

Table 2.6.3.1-21 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Reflood Mass and Energy Releases

	Break Path No.1*		Break Path No.2**	
Time	**Flow**	**Thousand**	**Flow**	**Thousand**
Seconds	**Lbm/sec**	**btu/sec**	**lbm/sec**	**btu/sec**
153.4	185.0	217.4	224.0	98.2
155.4	185.2	217.6	224.0	98.3
157.4	185.4	217.9	224.1	98.3
159.4	185.6	218.1	224.2	98.4
161.4	185.8	218.4	224.2	98.5
163.4	186.1	218.7	224.3	98.6
164.0	186.2	218.8	224.4	98.7
165.4	186.4	219.0	224.5	98.8
167.4	186.7	219.4	224.6	98.9
169.4	187.0	219.8	224.7	99.0
171.4	187.3	220.2	224.8	99.2
173.4	188.4	221.4	225.6	99.7
175.4	189.5	222.7	227.0	100.3
177.4	190.7	224.1	228.9	101.0
179.4	192.0	225.6	231.3	101.8
181.4	193.3	227.2	233.9	102.6
183.4	194.6	228.7	236.7	103.4
185.4	195.8	230.1	239.6	104.2
187.4	196.9	231.4	242.5	104.9
189.4	197.8	232.6	245.4	105.5
191.4	198.7	233.5	248.3	106.1
193.4	199.4	234.4	251.1	106.7
195.4	200.0	235.1	254.0	107.1
197.3	200.5	235.7	256.6	107.6
197.4	200.5	235.7	256.7	107.6

Table 2.6.3.1-21 Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows Reflood Mass and Energy Releases

	Break Path No.1*		Break Path No.2**	
Time	Flow	Thousand	Flow	Thousand
Seconds	Lbm/sec	btu/sec	lbm/sec	btu/sec
199.4	200.9	236.2	259.5	108.0
201.4	201.2	236.5	262.3	108.3
203.4	201.4	236.7	265.0	108.7
205.4	201.5	236.8	267.8	108.9
207.4	201.5	236.8	270.6	109.2
209.4	201.4	236.7	273.3	109.4
211.4	201.2	236.5	276.1	109.6
213.4	201.0	236.3	278.9	109.7
215.4	200.7	235.9	281.7	109.9
217.4	200.3	235.4	284.5	110.0
219.4	199.8	234.9	287.4	110.1
221.4	199.3	234.3	290.2	110.2
223.4	198.7	233.5	293.1	110.3
225.4	198.0	232.8	295.9	110.3
227.4	197.3	231.9	298.8	110.4
229.4	196.5	231.0	301.7	110.4
231.4	195.7	230.0	304.5	110.4
233.4	194.8	229.0	307.4	110.4
233.7	194.7	228.8	307.9	110.4
233.8	96.5	113.5	441.6	30.0

* mass and energy exiting the SG side of the break
** mass and energy exiting the pump side of the break

Table 2.6.3.1-22
Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows
Reflood Principal Parameters

Time	Flooding		Carryover	Core	Downcomer	Flow	Injection			
	Temp	Rate	Fraction	Height	Height	Fraction	Total	Accum ulator	Spill	Enthalpy
Seconds	°F	In/sec		Ft	Ft		(Pounds Mass Per Second)			Btu/lbm
28.2	201.0	0.000	0.000	0.00	0.00	0.250	0.0	0.0	0.0	0.00
29.0	197.6	23.016	0.000	0.67	1.57	0.000	7848.0	7848.0	0.0	89.66
29.2	195.7	25.242	0.000	1.07	1.49	0.000	7798.0	7798.0	0.0	89.66
29.5	194.8	2.916	0.116	1.32	2.14	0.233	7689.1	7689.1	0.0	89.66
29.6	194.7	2.933	0.137	1.34	2.45	0.252	7671.2	7671.2	0.0	89.66
30.5	194.5	2.467	0.311	1.50	5.39	0.329	7451.0	7451.0	0.0	89.66
31.3	194.3	2.386	0.409	1.60	7.84	0.345	7288.4	7288.4	0.0	89.66
35.0	193.8	4.510	0.639	2.00	16.12	0.588	6007.0	6007.0	0.0	89.66
36.4	193.5	4.194	0.678	2.17	16.12	0.587	5806.1	5806.1	0.0	89.66
39.8	193.3	3.759	0.718	2.51	16.12	0.582	5428.6	5428.6	0.0	89.66
45.4	194.0	3.360	0.740	2.95	16.12	0.571	4946.9	4946.9	0.0	89.66
46.0	194.1	3.530	0.742	3.00	16.12	0.584	5325.6	4787.2	0.0	87.47
53.1	195.9	3.217	0.752	3.50	16.12	0.573	4883.7	4332.5	0.0	87.22
53.4	196.0	3.207	0.752	3.52	16.12	0.573	4866.8	4315.1	0.0	87.21
54.4	196.4	3.269	0.753	3.59	16.05	0.584	551.8	0.0	0.0	68.03

Table 2.6.3.1-22
Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows
Reflood Principal Parameters

	Flooding		Carryover	Core	Downcomer	Flow	Injection			
Time	Temp	Rate	Fraction	Height	Height	Fraction	Total	Accum ulator	Spill	Enthalpy
Seconds	°F	In/sec		Ft	Ft		(Pounds Mass Per Second)			Btu/lbm
55.4	196.7	3.377	.753	3.65	15.85	0.588	541.3	0.0	0.0	68.03
60.7	199.2	3.021	.755	4.00	14.93	0.581	554.6	0.0	0.0	68.04
70.4	205.6	2.574	.757	4.55	13.83	0.569	570.7	0.0	0.0	68.03
79.6	212.8	2.290	.758	5.00	13.27	.558	580.3	0.0	0.0	68.03
91.4	222.3	2.051	.761	5.51	12.98	.546	588.2	0.0	0.0	68.04
104.0	230.9	1.902	.765	6.00	13.03	.537	592.1	0.0	0.0	68.03
119.4	239.6	1.808	.770	6.55	13.35	.532	594.2	0.0	0.0	68.03
132.6	245.9	1.768	.775	7.00	13.74	.530	595.0	0.0	0.0	68.03
149.4	252.7	1.746	.782	7.55	14.32	.530	595.5	0.0	0.0	68.03
164.0	257.9	1.741	.788	8.00	14.85	.531	595.6	0.0	0.0	68.03
165.4	258.3	1.741	.789	8.04	14.91	.531	595.6	0.0	0.0	68.03
181.4	263.2	1.768	.796	8.53	15.47	.538	594.9	0.0	0.0	68.03
193.4	266.4	1.786	.801	8.89	15.76	.546	594.0	0.0	0.0	68.03
197.3	267.4	1.785	.803	9.00	15.83	.548	593.9	0.0	0.0	68.03
215.4	271.5	1.748	.810	9.52	16.03	.555	593.7	0.0	0.0	68.03

Table 2.6.3.1-22
Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows
Reflood Principal Parameters

	Flooding		Carryover	Core	Downcomer	Flow	Injection			
Time	Temp	Rate	Fraction	Height	Height	Fraction	Total	Accumulator	Spill	Enthalpy
Seconds	°F	In/sec		Ft	Ft		(Pounds Mass Per Second)			Btu/lbm
233.7	274.9	1.668	.820	10.00	16.10	.558	594.5	0.0	0.0	68.03

Table 2.6.3.1-23
Double Ended Pump Suction Break With C_d = 0.6 and Minimum ECCS Flows
Mass Balance

Time (Seconds)		.00	28.20	28.20	233.72
		Mass (Thousand lbm)			
Initial	In RCS and Accumulator	743.78	743.78	743.78	743.78
Added Mass	Pumped Injection	.00	.00	.00	110.61
	Total Added	.00	.00	.00	110.61
*** Total Available ***		743.78	743.78	743.78	854.39
Distribution	Reactor Coolant	516.19	59.91	79.13	140.39
	Accumulator	227.59	162.30	143.08	.00
	Total Contents	743.78	222.21	222.21	140.39
Effluent	Break Flow	.00	521.56	521.56	702.57
	ECCS Spill	.00	.00	.00	.00
	Total Effluent	.00	521.56	521.56	702.57
*** Total Accountable ***		743.78	743.77	743.77	842.97

Table 2.6.3.1-24
Double Ended Pump Suction Break With C_D = 0.6 and Minimum ECCS Flows
Energy Balance

Time (Seconds)		.00	28.20	28.20	233.72
		Energy (Million btu)			
Initial Energy	In RCS, Accumulator, & Steam Generator	850.76	850.76	850.76	850.76
Added Energy	Pumped Injecti0n	.00	.00	.00	7.53
	Decay Heat	.00	9.07	9.07	34.33
	Heat From Secondary	.00	10.04	10.04	10.04
	Total Added	.00	19.10	19.10	51.89
*** Total Available ***		850.76	869.86	869.86	902.65
Distribution	Reactor Coolant	307.53	13.30	15.03	35.81
	Accumulator	20.41	14.55	12.83	.00
	Core Stored	24.79	13.09	13.09	4.67
	Primary Metal	153.93	146.66	146.66	119.42
	Secondary Metal	52.81	53.22	53.22	48.28
	Steam Generat0r	291.30	308.74	308.74	275.67
	Total Contents	850.76	549.56	549.56	483.85
Effluent	Break Flow	.00	319.71	319.71	407.75
	ECCS Spill	.00	.00	.00	.00
	Total Effluent	.00	319.71	319.71	407.75
*** Total Accountable ***		850.76	869.27	869.27	891.60

Table 2.6.3.1-25
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1	
	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
.00000	.0	.0
.00108	24418.3	13590.4
.101	42815.9	23902.3
.201	43794.3	24513.0
.302	43055.8	24181.7
.402	41787.2	23565.4
.501	40735.5	23079.2
.601	39660.4	22580.0
.701	38664.7	22120.6
.801	37735.6	21691.6
.902	36923.1	21319.0
1.00	36366.5	21080.8
1.10	35898.3	20881.2
1.20	35517.0	20723.5
1.30	35235.0	20616.9
1.40	34848.7	20445.2
1.50	34408.3	20234.6
1.60	34049.5	20067.3
1.70	33597.9	19840.8
1.80	33371.1	19746.9
1.90	33018.6	19579.3
2.00	32577.4	19357.7
2.10	32050.9	19084.3
2.20	31440.9	18759.6
2.30	30745.1	18382.5

Table 2.6.3.1-25
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1	
	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
2.40	29945.8	17942.9
2.50	29119.0	17484.9
2.60	27793.5	16722.4
2.70	27714.7	16707.3
2.80	27515.3	16623.1
2.90	27271.6	16514.3
3.00	26955.2	16361.1
3.10	26606.0	16185.8
3.20	26248.4	16000.9
3.30	25933.8	15838.1
3.40	25650.1	15695.7
3.50	25368.0	15556.9
3.60	25058.7	15402.9
3.70	24740.3	15239.7
3.80	24437.0	15080.9
3.90	24174.1	14944.5
4.00	23927.4	14818.6
4.20	23387.0	14536.6
4.40	22858.9	14235.7
4.60	22435.4	13985.3
4.80	21947.9	13679.9
5.00	21551.8	13414.6
5.20	21208.4	13178.2
5.40	20884.2	12955.0
5.60	20611.7	12764.0

Table 2.6.3.1-25
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows Blowdown Mass and Energy Releases

	Break Path No.1	
Time	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
5.80	20658.4	12711.2
6.00	20711.8	12684.2
6.20	20581.4	12586.5
6.40	20445.4	12473.7
6.60	20293.7	12364.6
6.80	20074.2	12231.1
7.00	19858.1	12100.9
7.20	19666.9	11984.7
7.40	19505.4	11884.3
7.60	19375.5	11811.1
7.80	19272.6	11751.4
8.00	19201.9	11701.5
8.20	19154.4	11660.4
8.40	19113.3	11623.6
8.60	19084.0	11596.4
8.80	19123.5	11606.5
9.00	19023.0	11587.8
9.20	19331.0	11661.6
9.40	19145.5	11558.6
9.60	18872.7	11423.1
9.80	18582.9	11291.6
10.0	18104.1	11091.6
10.2	17566.9	10855.1
10.2	17562.5	10853.2
10.4	17100.3	10644.3

Table 2.6.3.1-25
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1	
	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
10.6	16737.3	10473.0
10.8	16507.4	10351.7
11.0	16380.0	10278.0
11.2	16311.0	10227.8
11.4	16259.4	10185.9
11.6	16169.7	10130.7
11.8	16078.2	10073.1
12.0	16007.1	10020.1
12.2	15944.2	9964.3
12.4	15878.8	9906.4
12.6	15826.3	9858.6
12.8	15783.0	9821.8
13.0	15744.0	9785.5
13.2	15701.1	9744.9
13.4	15650.8	9700.9
13.6	15601.8	9657.5
13.8	15553.0	9613.8
14.0	15509.4	9572.8
14.2	15461.6	9529.9
14.4	15407.7	9485.9
14.6	15351.3	9441.5
14.8	15286.0	9392.7
15.0	15215.7	9342.5
15.2	15141.8	9291.6
15.4	15063.5	9238.8

Table 2.6.3.1-25
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1	
	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
15.6	14983.1	9185.7
15.8	14899.0	9131.6
16.0	14811.7	9076.3
16.2	14723.4	9021.1
16.4	14631.9	8964.9
16.6	14539.1	8908.8
16.8	14442.8	8851.4
17.0	14342.6	8792.5
17.2	14238.3	8732.0
17.4	14133.3	8671.5
17.6	14027.4	8611.2
17.8	13920.5	8550.6
18.0	13813.6	8490.4
18.2	13706.0	8430.3
18.4	13598.1	8370.3
18.6	13463.3	8293.6
18.8	13357.6	8236.2
19.0	13252.8	8178.9
19.2	13145.6	8120.5
19.4	13038.7	8062.5
19.6	12931.8	8004.8
19.8	12825.0	7947.3
20.0	12718.8	7890.4
20.2	12612.8	7833.6
20.4	12507.0	7777.2

Table 2.6.3.1-25
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows Blowdown Mass and Energy Releases

	Break Path No.1	
Time	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
20.6	12402.0	7721.3
20.8	12297.4	7665.7
21.0	12192.9	7610.2
21.2	12089.4	7555.4
21.4	11986.6	7501.0
21.6	11883.2	7446.5
21.8	11782.0	7393.1
22.0	11679.6	7339.4
22.2	11573.8	7283.6
22.4	11465.8	7226.6
22.6	11346.7	7163.4
22.8	11222.1	7097.7
23.0	11084.6	7025.3
23.2	10932.6	6945.7
23.4	10786.8	6868.7
23.6	10646.3	6793.7
23.8	10514.2	6722.0
24.0	10393.9	6654.6
24.2	10279.8	6589.7
24.4	10176.6	6529.9
24.6	10075.7	6471.2
24.8	9979.8	6415.9
25.0	9884.4	6361.6
25.2	9787.7	6308.0
25.4	9688.9	6254.7

Table 2.6.3.1-25
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1	
	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
25.6	9586.5	6201.2
25.8	9470.0	6142.0
26.0	9260.1	6028.0
26.2	9057.2	5912.4
26.4	8844.8	5797.7
26.6	8640.1	5690.4
26.8	8423.8	5572.4
27.0	8215.0	5445.7
27.2	8038.3	5321.5
27.4	7922.6	5213.8
27.6	7807.5	5106.7
27.8	7754.7	5024.7
28.0	7657.9	4915.2
28.2	7446.2	4765.0
28.4	7301.1	4652.2
28.6	7079.7	4519.3
28.8	6767.9	4361.1
29.0	6428.4	4200.6
29.2	6077.9	4039.3
29.4	5711.0	3874.6
29.6	5355.2	3716.7
29.8	5000.6	3564.1
30.0	4670.0	3422.2
30.2	4377.5	3297.0
30.4	4214.8	3211.0

Table 2.6.3.1-25
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1	
	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
30.6	3916.3	3079.0
30.8	3734.1	2974.1
31.0	3595.6	2876.6
31.2	3491.7	2786.0
31.4	3397.5	2695.0
31.6	3330.3	2609.8
31.8	3285.2	2531.1
32.0	3187.4	2435.0
32.2	3107.9	2340.1
32.4	2901.5	2217.6
32.6	2690.7	2108.3
32.8	2869.6	2077.5
33.0	3200.0	2061.4
33.2	3393.0	2013.8
33.4	3465.3	1962.9
33.6	3142.8	1819.7
33.8	2952.2	1701.7
34.0	3080.3	1679.3
34.2	3232.5	1664.7
34.4	3168.6	1581.1
34.6	3124.1	1478.3
34.8	3098.9	1379.3
35.0	2822.0	1248.1
35.2	2397.5	1130.8
35.4	2307.0	1044.0

Table 2.6.3.1-25

3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows Blowdown Mass and Energy Releases

Time	Break Path No.1	
	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
35.6	1868.5	868.4
35.8	1143.0	635.6
36.0	621.5	483.1
36.2	595.1	448.5
36.4	586.1	426.6
36.6	569.9	399.7
36.8	467.9	372.8
37.0	390.5	312.7
37.2	501.1	334.3
37.4	479.2	320.4
37.6	435.2	304.1
37.8	174.4	223.7
38.0	167.0	214.8
38.2	179.9	214.3
38.4	70.7	90.1
38.6	.0	.0

Table 2.6.3.1-26
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

	Break Path No.1	
Time	**Flow**	**Energy**
Seconds	**lbm/sec**	**Thousand btu/sec**
38.6	.0	.0
39.1	.0	.0
39.3	.0	.0
39.4	.0	.0
39.5	.0	.0
39.5	.0	.0
39.6	49.6	58.2
39.7	33.1	38.9
39.8	23.1	27.1
39.9	25.9	30.4
40.0	32.4	38.1
40.1	38.8	45.5
40.2	43.1	50.6
40.3	47.2	55.4
40.4	51.1	60.0
40.5	54.7	64.3
40.6	58.3	68.4
40.7	61.6	72.3
40.8	64.8	76.1
40.9	68.0	79.8
41.0	71.0	83.4
41.1	73.9	86.8
41.2	76.7	90.1
41.3	79.5	93.4
41.4	82.2	96.5

Table 2.6.3.1-26
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

	Break Path No.1	
Time	**Flow**	**Energy**
Seconds	**lbm/sec**	**Thousand btu/sec**
41.5	84.8	99.6
41.6	87.4	102.6
42.6	110.2	129.5
43.6	129.6	152.4
44.7	5501.6	1219.4
45.3	5629.4	1272.1
45.7	5989.7	1338.2
46.7	5914.6	1320.6
47.7	5832.9	1301.5
48.7	5747.7	1281.4
49.7	5662.4	1261.3
49.8	5654.0	1259.3
50.7	5577.6	1241.7
51.7	5493.1	1222.7
52.7	5411.2	1204.4
53.7	5332.2	1186.7
54.7	5255.9	1169.7
55.7	5182.4	1153.4
56.7	5111.5	1137.7
57.7	5043.1	1122.5
58.7	4977.2	1108.0
59.7	4913.5	1094.0
60.7	4852.0	1080.5
61.7	4792.6	1067.4
62.7	4735.1	1054.9

Table 2.6.3.1-26
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

	Break Path No.1	
Time	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
63.7	4679.4	1042.7
64.7	4625.6	1031.0
65.7	4573.4	1019.6
66.7	687.8	675.7
67.7	1097.8	1279.0
68.6	1100.9	1284.3
68.7	1094.7	1276.7
69.7	1023.4	1189.7
70.7	1008.1	1171.3
71.7	966.7	1121.0
72.7	919.0	1047.9
73.8	843.5	919.7
74.8	777.1	815.3
75.8	713.7	719.6
76.8	667.5	655.8
77.8	628.1	601.1
78.6	591.0	550.7
78.8	586.4	544.4
79.8	571.4	524.5
80.8	561.0	510.7
81.8	551.6	498.4
82.8	542.9	487.0
83.8	534.8	476.4
84.8	527.2	466.4
85.8	520.0	457.1

Table 2.6.3.1-26
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

	Break Path No.1	
Time	**Flow**	**Energy**
Seconds	**lbm/sec**	**Thousand btu/sec**
86.8	513.3	448.3
87.8	507.0	440.1
88.8	501.0	432.4
89.8	495.4	425.1
90.8	490.1	418.2
91.8	485.1	411.8
92.8	480.4	405.7
93.8	476.0	399.9
94.8	472.5	395.5
95.8	469.7	392.0
96.8	467.0	388.6
97.8	464.4	385.3
98.8	461.9	382.1
99.5	460.2	380.0
99.8	459.5	379.1
101.8	455.0	373.5
103.8	451.0	368.4
105.8	447.2	363.7
107.8	443.7	359.3
109.8	440.5	355.3
111.8	437.5	351.5
113.8	434.7	348.0
115.8	432.1	344.8
117.8	429.8	341.9
119.8	427.6	339.2

Table 2.6.3.1-26
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

	Break Path No.1	
Time	**Flow**	**Energy**
Seconds	**lbm/sec**	**Thousand btu/sec**
121.8	425.7	336.8
123.8	424.8	335.7
125.8	424.5	335.3
126.2	424.4	335.2
127.8	424.2	334.9
129.8	423.9	334.6
131.8	423.6	334.2
133.8	423.4	333.8
135.8	423.1	333.5
137.8	422.8	333.1
139.8	422.6	332.8
141.8	422.3	332.5
143.8	422.1	332.1
145.8	421.8	331.8
147.8	421.6	331.5
149.8	421.4	331.2
151.8	421.3	331.1
153.8	421.2	330.9
155.8	421.1	330.8
156.6	421.1	330.8
157.8	421.0	330.8
159.8	421.0	330.7
161.8	420.9	330.6
163.8	420.8	330.5
165.8	420.8	330.4

Table 2.6.3.1-26
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

	Break Path No.1	
Time	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
167.8	420.7	330.3
169.8	420.7	330.3
171.8	420.6	330.2
173.8	420.6	330.2
175.8	420.6	330.1
177.8	420.5	330.0
179.8	420.5	330.0
181.8	420.4	329.9
183.8	420.4	329.9
185.8	420.4	329.9
187.8	420.4	329.8
189.8	420.3	329.8
190.2	420.3	329.8
191.8	420.3	329.8
193.8	420.3	329.7
195.8	420.3	329.7
197.8	420.3	329.7
199.8	420.3	329.7
201.8	420.3	329.7
203.8	420.3	329.6
205.8	420.2	329.6
207.8	420.2	329.6
209.8	420.2	329.6
211.8	420.3	329.6
213.8	420.3	329.6

Table 2.6.3.1-26
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1	
	Flow	Energy
Seconds	lbm/sec	Thousand btu/sec
215.8	420.3	329.6
217.8	420.3	329.6
219.8	420.3	329.6
221.8	420.3	329.6
223.8	420.3	329.7
225.8	420.3	329.7
227.6	420.4	329.7

Table 2.6.3.1-27
3.0 ft^2 Pump Suction Split Break with Minimum ECCS Flows
Reflood Principal Parameters

Time	Flooding		Carryover Fraction	Core Height	Downcomer Height	Flow	Injection			
	Temp	Rate				Fraction	Total	Accumulator	Spill	Enthalpy
sec	ºF	in/sec	(--)	ft	ft		lbm/sec			BTU/lbm
38.6	246.1	.000	.000	.00	.00	.250	.0	.0	.0	.00
39.3	242.1	21.500	.000	.51	1.66	.000	8315.9	8315.9	.0	89.66
39.5	238.6	25.941	.000	1.01	1.63	.000	8228.7	8228.7	.0	89.66
40.9	235.8	2.449	.321	1.50	5.88	.338	7822.5	7822.5	.0	89.66
41.6	235.4	2.381	.410	1.59	8.22	.350	7651.5	7651.5	.0	89.66
44.7	233.4	4.724	.616	1.92	16.11	.607	6410.8	6410.8	.0	89.66
45.3	232.8	4.623	.644	2.00	16.12	.601	6241.9	6241.9	.0	89.66
45.7	232.3	4.750	.658	2.06	16.12	.611	6584.5	6080.2	.0	88.00
46.7	231.3	4.506	.684	2.18	16.12	.610	6432.9	5926.7	.0	87.96
49.8	228.9	4.063	.722	2.51	16.12	.606	6064.9	5548.7	.0	87.82
55.7	226.1	3.617	.745	3.00	16.12	.596	5517.7	4985.9	.0	87.58
62.7	224.5	3.288	.754	3.50	16.12	.585	5028.9	4483.4	.0	87.31
65.7	224.2	3.178	.756	3.70	16.12	.580	4855.0	4304.7	.0	87.21
66.7	224.1	3.653	.743	3.77	16.05	.584	499.9	.0	.0	68.03
67.7	224.0	5.988	.726	3.87	15.61	.633	127.6	.0	.0	68.03
68.6	223.7	5.986	.720	4.00	14.92	.619	126.7	.0	.0	68.03

Table 2.6.3.1-27
3.0 ft^2 Pump Suction Split Break with Minimum ECCS Flows
Reflood Principal Parameters

Time	Flooding		Carryover Fraction	Core Height	Downcomer Height	Flow	Injection			
	Temp	Rate				Fraction	Total	Accumulator	Spill	Enthalpy
sec	ºF	in/sec	(--)	ft	ft		lbm/sec			BTU/lbm
72.7	223.6	4.922	.725	4.52	12.16	.653	173.9	.0	.0	68.03
78.6	225.2	2.868	.749	5.00	10.39	.671	531.4	.0	.0	68.04
88.8	230.7	2.328	.758	5.54	9.51	.700	568.9	.0	.0	68.03
99.5	237.4	2.079	.764	6.00	9.21	.722	582.4	.0	.0	68.03
113.8	244.9	1.924	.769	6.56	9.20	.745	588.4	.0	.0	68.03
126.2	250.3	1.847	.774	7.00	9.40	.758	590.7	.0	.0	68.03
141.8	256.1	1.791	.780	7.53	9.73	.769	591.6	.0	.0	68.03
156.6	260.8	1.754	.786	8.00	10.10	.776	592.1	.0	.0	68.03
173.8	265.5	1.726	.793	8.53	10.58	.779	592.4	.0	.0	68.03
190.2	269.3	1.709	.801	9.00	11.08	.778	592.6	.0	.0	68.03
209.8	273.2	1.699	.812	9.54	11.76	.772	592.8	.0	.0	68.03
217.8	274.6	1.698	.817	9.75	12.06	.768	592.9	.0	.0	68.03
227.6	276.2	1.699	.823	10.00	12.45	.762	593.0	.0	.0	68.03

Table 2.6.3.1-28
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows
Mass Balance

	Time (Seconds)	.00	38.60	38.60	227.59
		MASS (THOUSAND LBM)			
Initial	In RCS and ACC	743.78	743.78	743.78	743.78
Added Mass	Pumped Injection	.00	.00	.00	102.36
	Total Added	.00	.00	.00	102.36
*** Total Available ***		743.50	743.78	743.78	846.14
Distribution	Reactor Coolant	516.19	72.83	72.90	127.84
	Accumulator	227.59	155.25	155.18	.00
	Total Contents	743.78	228.08	228.08	127.84
Effluent	Break Flow	.00	515.70	515.70	707.22
	ECCS Spill	.00	.00	.00	.00
	Total Effluent	.00	515.70	515.70	707.22
*** Total Accountable ***		743.50	743.77	743.77	835.06

Table 2.6.3.1-29
3.0 ft^2 Pump Suction Split Break With Minimum ECCS Flows
Energy Balance

Time (Seconds)		0.00	38.60	38.60	227.59
		Energy (Million BTU)			
Initial Energy	In RCS, Accumulator, and Steam Generator	850.76	850.76	850.76	850.76
Added Energy	Pumped Injecti0n	.00	.00	.00	6.96
	Decay Heat	.00	11.81	11.81	34.79
	Heat from Secondary	.00	10.26	10.26	10.26
	Total Added	.00	22.08	22.08	52.02
Total Available		850.76	872.83	872.83	902.78
Distribution	Reactor Coolant	307.53	16.56	16.57	33.12
	Accumulator	20.41	13.92	13.91	.00
	Core Stored	24.79	13.18	13.18	4.67
	Primary Metal	153.93	146.55	146.55	119.21
	Secondary Metal	52.81	53.52	53.52	48.50
	Steam Generat0r	291.30	310.95	310.95	278.57
	Total Contents	850.76	554.68	554.68	484.08
Effluent	Break Flow	.00	317.57	317.57	407.48
	ECCS Spill	.00	.00	.00	.00
	Total Effluent	.00	317.57	317.57	407.48
*** Total Accountable ***		850.76	872.25	872.25	891.56

Table 2.6.3.1-30
Double Ended Cold Leg Break With Minimum ECCS Flows
Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
.00000	.0	.0	.0	.0
.00106	31491.5	17526.7	31490.2	17525.3
.00209	33477.0	18632.6	33383.7	18578.1
.101	26465.0	14733.8	59655.8	33357.0
.201	23873.6	13317.6	60778.1	33990.8
.301	23431.0	13076.1	59054.2	33016.9
.402	23189.8	12944.2	58631.8	32780.3
.501	22974.5	12830.7	58506.8	32709.8
.602	22794.8	12742.8	57981.1	32411.5
.701	22702.0	12709.8	56836.0	31766.9
.801	22607.5	12681.4	55380.3	30950.2
.902	22416.3	12602.3	54386.9	30395.0
1.00	22171.0	12496.0	53593.9	29955.4
1.10	21906.1	12381.7	53582.3	29961.4
1.20	21638.7	12267.6	53001.6	29654.1
1.30	21447.4	12199.1	51399.9	28779.2
1.40	21267.1	12137.8	50638.5	28372.9
1.50	21073.1	12068.6	49022.2	27486.4
1.60	20835.9	11973.0	48872.0	27419.7
1.70	20632.3	11895.7	48124.6	27023.0
1.80	20476.6	11844.8	46563.2	26174.6
1.90	20399.2	11838.7	44921.7	25277.3
2.00	20304.5	11820.9	43796.2	24662.3
2.10	19960.7	11655.5	42724.0	24071.0
2.20	19625.6	11492.8	42388.1	23894.2

Table 2.6.3.1-30
Double Ended Cold Leg Break With Minimum ECCS Flows
Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
2.30	19002.0	11156.0	40870.2	23053.6
2.40	17811.5	10482.0	40135.5	22655.5
2.50	16850.8	9939.0	39146.9	22112.1
2.60	15990.6	9450.7	38369.0	21682.7
2.70	15240.3	9024.0	37378.3	21129.6
2.80	14614.8	8668.8	36512.4	20644.6
2.90	14119.3	8389.4	35980.3	20348.5
3.00	13755.9	8187.9	35443.3	20050.3
3.10	13485.4	8041.3	34539.4	19544.4
3.20	13251.9	7916.8	34379.1	19456.2
3.30	13029.0	7798.6	34009.8	19247.7
3.40	12806.2	7681.4	33455.5	18932.1
3.50	12586.0	7567.0	32559.3	18420.4
3.60	12382.3	7464.5	31176.7	17630.1
3.70	12192.4	7372.8	29492.3	16665.9
3.80	12005.8	7286.3	28150.4	15893.4
3.90	11822.3	7204.6	27500.9	15514.3
4.00	11642.0	7128.1	27171.7	15318.2
4.20	11286.3	6988.5	26653.9	15013.3
4.40	10918.3	6852.9	26065.6	14675.6
4.60	10537.3	6716.2	25701.2	14466.5
4.80	10149.2	6572.2	25292.3	14234.7
5.00	9744.4	6408.5	25171.8	14166.6
5.20	9399.0	6266.3	24922.3	14032.4
5.40	9101.5	6133.2	24565.1	13850.5

Table 2.6.3.1-30
Double Ended Cold Leg Break With Minimum ECCS Flows
Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
5.60	8848.2	6008.5	24395.4	13788.9
5.80	8627.1	5893.0	24235.5	13719.0
6.00	8438.5	5800.6	24053.8	13639.1
6.20	8229.1	5705.6	23717.3	13478.6
6.40	7986.3	5599.9	23399.9	13333.2
6.60	7716.3	5479.4	23002.5	13151.1
6.80	7427.4	5341.1	22666.5	13013.7
7.00	7156.3	5202.2	22294.7	12859.4
7.20	6901.8	5058.8	21912.2	12693.6
7.40	6674.9	4914.4	21553.3	12530.7
7.60	6490.0	4777.9	21192.0	12366.7
7.80	6352.0	4654.7	20826.4	12203.1
8.00	6379.6	4639.7	20753.9	12239.1
8.20	6339.2	4555.2	20277.9	12040.2
8.40	6424.3	4555.3	20019.8	11935.3
8.60	6597.0	4645.6	19604.6	11785.5
8.80	6639.3	4738.1	19189.5	11668.0
9.00	6358.7	4726.2	18754.1	11552.3
9.20	5844.0	4582.6	18144.1	11406.4
9.40	5393.6	4366.9	16930.7	10872.3
9.60	5149.6	4183.0	15632.6	10334.7
9.80	5032.8	4054.6	14375.4	9794.7
10.0	4953.0	3950.7	13088.8	9214.9
10.2	4884.3	3863.6	12322.5	8816.9
10.4	4804.8	3779.6	11200.9	8340.3

Table 2.6.3.1-30
Double Ended Cold Leg Break With Minimum ECCS Flows
Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
10.6	4735.0	3718.0	10705.6	8083.0
11.0	5737.1	3744.1	9875.2	7611.6
11.2	6619.2	3843.7	9613.6	7401.5
11.4	6815.4	3803.8	9428.6	7229.7
11.6	6759.2	3724.0	9233.2	7059.8
11.8	6651.3	3647.8	9091.0	6908.0
12.0	6534.7	3580.2	8950.7	6762.3
12.2	6405.7	3511.4	8834.9	6627.4
12.4	6276.0	3441.2	8726.7	6500.5
12.6	6154.1	3371.3	8617.6	6377.0
12.8	6045.2	3306.5	8503.1	6256.6
13.0	5945.4	3246.7	8336.4	6123.3
13.2	5850.2	3189.7	8175.2	5987.6
13.4	5756.3	3134.1	8033.5	5849.4
13.6	5664.5	3081.1	7894.7	5707.7
13.8	5571.2	3029.7	7703.8	5536.9
14.0	5463.9	2970.7	7284.1	5289.5
14.2	5335.8	2901.0	6749.9	5015.3
14.4	5190.8	2830.0	6274.9	4751.8
14.6	5028.9	2761.5	6043.4	4516.7
14.8	4853.8	2696.0	5918.8	4301.1
15.0	4682.0	2639.5	5299.1	4136.7
15.2	4509.8	2577.6	5690.3	3974.4
15.4	4360.3	2513.4	5373.7	3766.0
15.6	4247.6	2464.2	5604.2	3581.6

Table 2.6.3.1-30
Double Ended Cold Leg Break With Minimum ECCS Flows
Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
15.8	4151.3	2456.3	5416.5	3401.5
16.0	4003.0	2451.1	5339.8	3209.1
16.2	3582.5	2109.0	5269.4	3002.8
16.4	3243.8	1676.6	5170.2	2817.6
16.6	3234.9	1620.8	4949.9	2672.4
16.8	3181.7	1537.5	4957.5	2530.1
17.0	3137.2	1481.4	5099.6	2435.6
17.2	3085.6	1420.7	5232.0	2384.4
17.4	3029.6	1358.2	5283.3	2318.8
17.6	2971.4	1297.4	5284.9	2247.8
17.8	2920.6	1238.5	5213.1	2155.8
18.0	2863.1	1180.9	5093.2	2052.0
18.2	2811.8	1126.2	4926.7	1937.2
18.4	2759.4	1071.5	4733.6	1818.7
18.6	2709.0	1019.9	4535.9	1705.1
18.8	2662.2	969.7	4319.0	1589.8
19.0	2608.7	916.4	4215.2	1519.2
19.2	2555.1	864.6	4101.9	1447.5
19.4	2495.9	813.2	3997.9	1382.1
19.6	2429.0	760.2	3867.8	1309.4
19.8	2339.2	701.7	3752.9	1243.1
20.0	2206.0	634.7	3648.5	1182.1
20.2	1960.0	541.7	3541.2	1122.2
20.4	1590.6	423.6	3455.2	1070.8
20.6	.0	.0	3400.9	1030.4

Table 2.6.3.1-30
Double Ended Cold Leg Break With Minimum ECCS Flows
Blowdown Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
20.8	.0	.0	3410.9	1010.2
21.0	.0	.0	3420.5	991.5
21.2	.0	.0	3373.0	960.1
21.4	.0	.0	3763.2	1044.4
21.6	.0	.0	4318.4	1163.1
21.8	.0	.0	4305.8	1134.1
22.0	.0	.0	3577.0	925.9
22.2	.0	.0	2389.1	610.6
22.4	.0	.0	.0	.0

* mass and energy exiting the broken loop side of the break
** mass and energy exiting the vessel side of the break

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
22.4	.0	.0	.0	.0
23.5	1682.1	150.8	.0	.0
23.6	1677.4	150.4	.0	.0
23.7	1672.7	150.0	.0	.0
23.8	1668.1	149.6	.0	.0
23.9	1663.5	149.2	.0	.0
24.0	1658.9	148.7	.0	.0
24.1	1654.4	148.3	.0	.0
24.2	1649.8	147.9	.0	.0
24.2	1645.3	147.5	.0	.0
24.3	1640.8	147.1	.0	.0
24.3	1637.0	146.8	.0	.0
24.4	1632.2	146.4	.0	.0
24.5	1628.9	146.1	.0	.0
24.6	1624.5	145.7	.0	.0
24.7	1620.1	145.3	.0	.0
24.8	1614.1	144.7	.0	.0
24.9	1609.5	144.3	.0	.0
25.0	1605.8	144.0	.0	.0
25.1	1601.8	143.6	.0	.0
25.2	1598.7	143.3	.0	.0
25.3	1595.1	143.0	.0	.0
25.4	1590.7	142.6	.0	.0
25.5	1587.0	142.3	.0	.0
26.5	1573.7	163.4	.0	.0

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
27.4	1556.2	175.6	.0	.0
27.5	1555.0	176.3	.0	.0
28.5	1534.6	184.8	.0	.0
29.5	1512.4	190.0	.0	.0
30.5	1494.7	199.3	2149.2	308.8
31.6	1480.4	208.5	4128.0	601.6
32.6	1455.3	206.1	4111.9	603.0
33.6	1430.9	203.4	4046.9	596.6
34.2	1416.8	201.8	4007.1	592.7
34.6	1407.6	200.7	3980.7	590.0
35.6	1385.2	198.2	3915.3	583.4
36.6	1363.8	195.7	3851.4	576.8
37.6	1343.2	193.4	3789.2	570.4
38.6	1323.3	191.2	3728.8	564.0
39.6	1304.2	189.0	3670.3	557.9
40.6	1285.8	186.9	3613.6	551.9
41.6	65.6	77.1	3558.7	546.0
42.6	65.2	76.7	3505.6	540.3
43.6	64.9	76.3	3454.2	534.8
44.6	79.6	93.6	240.7	283.1
44.7	79.5	93.5	240.4	282.8
45.6	218.1	89.4	183.3	184.1
46.6	217.3	88.4	186.8	182.9
47.6	217.4	88.5	189.9	183.3
48.6	217.6	88.7	192.9	183.7

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
49.6	217.8	88.9	196.1	184.1
50.6	218.0	89.1	199.2	184.5
51.6	218.2	89.2	202.2	184.8
52.6	218.4	89.4	205.3	185.2
53.6	218.5	89.6	208.2	185.5
54.6	218.7	89.7	211.2	185.8
55.6	218.9	89.9	214.0	186.1
56.6	219.0	90.0	216.8	186.4
57.4	219.1	90.1	218.9	186.6
57.6	219.2	90.1	219.4	186.7
58.6	219.3	90.3	222.0	186.9
59.6	219.4	90.4	224.5	187.1
60.6	219.6	90.5	226.9	187.2
61.6	219.7	90.6	229.2	187.3
62.6	219.8	90.6	231.4	187.4
63.6	219.9	90.7	233.5	187.5
64.6	220.0	90.8	235.5	187.6
65.6	220.1	90.8	237.4	187.6
66.6	220.1	90.9	239.3	187.6
67.6	220.2	90.9	241.0	187.6
68.6	220.3	90.9	242.7	187.5
69.6	220.3	91.0	244.3	187.4
70.6	220.4	91.0	245.8	187.3
71.3	220.4	91.0	246.9	187.3
71.6	220.4	91.0	247.3	187.2

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
72.6	220.5	91.0	248.7	187.1
73.6	220.5	91.0	250.0	186.9
74.6	220.6	91.0	251.3	186.8
75.6	220.6	91.0	252.5	186.6
76.6	220.6	91.0	253.7	186.4
77.6	220.7	91.0	254.8	186.2
78.6	220.7	91.0	255.9	186.0
79.6	220.7	91.0	257.0	185.8
80.6	220.7	90.9	258.0	185.6
81.6	220.7	90.9	259.0	185.4
82.6	220.7	90.9	259.9	185.1
83.6	220.8	90.8	260.8	184.9
85.6	220.8	90.8	262.6	184.4
86.2	220.8	90.8	263.1	184.2
87.6	220.8	90.7	264.3	183.8
89.6	220.8	90.6	265.9	183.3
91.6	220.8	90.5	267.4	182.7
93.6	220.8	90.5	268.9	182.2
95.6	220.8	90.4	270.3	181.6
97.6	220.8	90.3	271.7	181.0
99.6	220.8	90.2	273.0	180.5
101.6	220.8	90.1	274.1	180.0
103.6	220.8	90.1	275.0	179.6
105.6	220.7	90.0	275.9	179.1
107.6	220.6	89.9	276.7	178.7

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
109.6	220.6	89.8	277.6	178.3
111.6	220.5	89.7	278.5	177.9
113.6	220.5	89.7	279.3	177.5
115.6	220.4	89.6	280.1	177.1
117.6	220.4	89.5	280.9	176.7
119.1	220.3	89.4	281.6	176.4
119.6	220.3	89.4	281.8	176.3
121.6	220.3	89.3	282.6	175.9
123.6	220.2	89.3	283.4	175.5
125.6	220.1	89.2	284.1	175.1
127.6	220.1	89.1	284.9	174.7
129.6	220.0	89.0	285.7	174.3
131.6	220.0	88.9	286.5	173.9
133.6	219.9	88.8	287.3	173.5
135.6	219.9	88.8	288.0	173.1
137.6	219.8	88.7	288.8	172.7
139.6	219.8	88.6	289.5	172.3
141.6	219.7	88.5	290.3	171.9
143.6	219.7	88.4	291.1	171.6
145.6	219.6	88.4	291.8	171.2
147.6	219.6	88.3	292.6	170.8
149.6	219.5	88.2	293.3	170.4
151.6	219.4	88.1	294.1	170.1
153.6	219.4	88.0	294.8	169.7
155.6	219.3	88.0	295.6	169.3

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
155.9	219.3	88.0	295.7	169.3
157.6	219.3	87.9	296.3	168.9
159.6	219.2	87.8	297.0	168.6
161.6	219.2	87.7	297.8	168.2
163.6	219.1	87.6	298.5	167.8
165.6	219.1	87.6	299.3	167.5
167.6	219.0	87.5	300.0	167.1
169.6	218.9	87.4	300.8	166.8
171.6	218.9	87.3	301.5	166.4
173.6	218.8	87.2	302.3	166.0
175.6	218.8	87.1	303.0	165.7
177.6	218.7	87.1	303.8	165.3
179.6	218.7	87.0	304.5	165.0
181.6	218.6	86.9	305.2	164.6
183.6	218.5	86.8	306.0	164.3
185.6	218.5	86.7	306.7	163.9
187.6	218.4	86.6	307.5	163.6
189.6	218.4	86.6	308.3	163.3
191.6	218.3	86.5	309.0	162.9
193.6	218.3	86.4	309.8	162.6
195.6	218.2	86.3	310.5	162.3
197.6	218.1	86.2	311.3	161.9
199.6	218.1	86.1	312.1	161.6
201.6	218.0	86.0	312.8	161.3
203.6	218.0	85.9	313.6	161.0

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
205.6	217.9	85.9	314.4	160.6
207.6	217.8	85.8	315.1	160.3
209.6	217.8	85.7	315.9	160.0
211.6	217.7	85.6	316.7	159.7
213.6	217.7	85.5	317.4	159.4
215.6	217.6	85.4	318.2	159.1
217.6	217.5	85.3	319.0	158.8
219.6	217.5	85.2	319.8	158.5
221.6	217.4	85.1	320.6	158.2
223.6	217.3	85.1	321.4	157.9
225.6	217.3	85.0	322.2	157.6
227.6	217.2	84.9	323.1	157.3
229.6	217.1	84.8	323.9	157.0
231.6	217.1	84.7	324.7	156.8
233.6	217.0	84.6	325.6	156.5
235.6	216.9	84.5	326.4	156.2
237.6	216.9	84.4	327.3	156.0
239.6	216.8	84.3	328.1	155.7
241.6	216.7	84.2	329.0	155.5
243.6	216.7	84.2	329.9	155.2
245.6	216.6	84.1	330.8	155.0
247.3	216.6	84.0	331.6	154.8
247.6	216.6	84.0	331.7	154.8
249.6	216.5	83.9	332.7	154.5
251.6	216.4	83.8	333.6	154.3

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
253.6	216.4	83.7	334.5	154.1
255.6	216.3	83.7	335.5	153.9
257.6	216.3	83.6	336.5	153.7
259.6	216.2	83.5	337.5	153.5
261.6	216.2	83.5	338.6	153.3
263.6	216.1	83.4	339.6	153.2
265.6	216.1	83.3	340.7	153.0
267.6	216.1	83.3	341.8	152.9
269.6	216.0	83.2	343.0	152.7
271.6	216.0	83.1	344.1	152.6
273.6	216.0	83.1	345.4	152.5
275.6	215.9	83.0	346.6	152.4
277.6	215.9	83.0	348.0	152.4
279.6	215.9	83.0	349.4	152.3
281.6	215.8	82.9	350.8	152.3
283.6	215.8	82.8	352.2	152.3
285.6	215.8	82.8	353.7	152.3
287.6	215.7	82.7	355.3	152.3
289.6	215.7	82.7	356.9	152.4
291.6	215.7	82.6	358.6	152.5
293.6	215.7	82.6	360.5	152.6
295.6	215.7	82.6	362.4	152.8
297.6	215.7	82.6	364.6	153.0
299.6	215.7	82.6	367.0	153.3
301.6	215.7	82.6	369.7	153.7

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
303.6	215.7	82.6	372.2	154.0
305.6	215.7	82.5	372.3	153.7
307.6	215.6	82.5	372.5	153.5
309.6	215.6	82.4	372.6	153.2
311.6	215.5	82.3	372.7	153.0
313.6	215.4	82.2	372.9	152.8
315.6	215.4	82.1	373.0	152.5
317.6	215.3	82.0	373.1	152.3
319.6	215.2	81.9	373.3	152.1
321.6	215.2	81.8	373.4	151.8
323.6	215.1	81.7	373.5	151.6
325.6	215.0	81.6	373.7	151.3
327.6	215.0	81.5	373.8	151.1
329.6	214.9	81.4	374.0	150.9
329.7	214.9	81.4	374.0	150.9
331.6	214.8	81.4	374.1	150.6
333.6	214.8	81.3	374.2	150.4
335.6	214.7	81.2	374.4	150.2
337.6	214.6	81.1	374.5	149.9
339.6	214.6	81.0	374.6	149.7
341.6	214.5	80.9	374.8	149.5
343.6	214.4	80.8	374.9	149.2
345.6	214.3	80.7	375.1	149.0
347.6	214.3	80.6	375.2	148.8
349.6	214.2	80.5	375.3	148.5

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
351.6	214.1	80.4	375.4	148.3
353.6	214.0	80.3	375.5	148.1
355.6	214.0	80.2	375.6	147.8
357.6	213.9	80.1	375.7	147.6
359.6	213.8	80.0	375.8	147.3
361.6	213.7	79.9	376.0	147.1
363.6	213.7	79.8	376.1	146.9
365.6	213.6	79.7	376.2	146.6
367.6	213.5	79.6	376.3	146.4
369.6	213.4	79.4	376.4	146.2
371.6	213.4	79.3	376.5	145.9
373.6	213.3	79.2	376.6	145.7
375.6	213.2	79.1	376.8	145.5
377.6	213.1	79.0	376.9	145.2
379.6	213.0	78.9	377.0	145.0
381.6	212.9	78.7	377.1	144.8
383.6	212.8	78.6	377.3	144.6
385.6	212.7	78.5	377.4	144.3
387.6	212.6	78.3	377.5	144.1
389.6	212.5	78.2	377.7	143.9
391.6	212.4	78.1	377.8	143.7
393.6	212.3	78.0	377.9	143.4
395.6	212.2	77.8	378.0	143.2
397.6	212.1	77.7	378.2	143.0
399.6	212.0	77.6	378.3	142.8

Table 2.6.3.1-31
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Mass and Energy Releases

Time	Break Path No.1*		Break Path No.2**	
sec	lbm/sec	Thousand btu/sec	lbm/sec	Thousand btu/sec
401.6	211.9	77.5	378.4	142.5
403.6	211.8	77.3	378.5	142.3
405.6	211.7	77.2	378.6	142.1
407.6	211.6	77.1	378.7	141.9
409.6	211.5	77.0	378.8	141.7
411.6	211.5	76.9	379.0	141.5
413.6	211.4	76.8	379.1	141.3
415.6	211.3	76.7	379.2	141.1
417.6	211.2	76.5	379.3	140.9
419.6	211.1	76.4	379.4	140.7
421.6	211.0	76.3	379.5	140.5
423.6	210.9	76.2	379.6	140.4
425.6	210.8	76.1	379.7	140.2
427.6	210.7	76.0	379.9	140.0
429.6	210.6	75.9	380.0	139.8
431.6	210.5	75.8	380.1	139.6
433.6	210.4	75.6	380.2	139.4
435.6	210.3	75.5	380.3	139.2
437.6	210.2	75.4	380.5	139.0
439.6	210.1	75.3	380.6	138.8
441.6	210.0	75.2	380.7	138.6
442.9	210.0	75.1	380.8	138.5

* mass and energy exiting the broken loop side of the break
** mass and energy exiting the vessel side of the break

Table 2.6.3.1-32
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Principal Parameters

Time	Flooding Temp	Flooding Rate		Carryover Fraction	Core Height	Downcomer Height	Flow Fraction	Injection Total	Injection Accumulator	Injection Spill
sec	ºF	in/sec			ft	ft		lbm/sec		
22.4	165.7	0.000	0.000	0.00	0.00	0.250	0.0	0.0	0.0	0.00
24.1	165.4	44.563	0.000	0.50	3.57	0.000	7144.4	7144.4	0.0	89.66
24.2	165.1	42.605	0.000	0.86	3.09	0.000	7122.8	7122.8	0.0	89.66
24.2	164.9	40.976	0.000	1.04	2.86	0.000	7101.3	7101.3	0.0	89.66
25.2	165.1	-2.250	0.117	1.33	4.72	0.000	6880.8	6880.8	0.0	89.66
26.5	165.6	2.421	0.296	1.49	7.63	0.112	6659.9	6659.9	0.0	89.66
27.4	166.0	2.112	0.403	1.60	9.62	0.153	6515.6	6515.6	0.0	89.66
29.5	166.9	2.022	0.532	1.78	13.97	0.182	6227.8	6227.8	0.0	89.66
30.5	167.3	2.084	0.571	1.86	15.84	0.198	6090.6	6090.6	0.0	89.66
32.6	168.2	1.995	0.619	2.00	16.12	0.220	5841.8	5841.8	0.0	89.66
42.6	173.3	1.704	0.694	2.51	16.12	0.216	3757.1	3757.1	0.0	89.66
43.6	173.8	1.690	0.697	2.55	16.12	0.215	3701.9	3701.9	0.0	89.66
44.6	174.3	1.786	0.701	2.60	15.99	0.248	0.0	0.0	0.0	0.00
55.6	180.9	1.625	0.720	3.03	15.98	0.227	602.2	0.0	0.0	68.03
68.6	190.0	1.571	0.731	3.51	16.08	0.234	603.8	0.0	0.0	68.03
83.6	201.4	1.510	0.740	4.02	16.12	0.240	606.0	0.0	0.0	68.03
99.6	212.4	1.449	0.747	4.52	16.12	0.246	608.3	0.0	0.0	68.03

Table 2.6.3.1-32
Double Ended Cold Leg Break With Minimum ECCS Flows
Reflood Principal Parameters

Time	Flooding			Carryover Fraction	Core Height	Downcomer Height	Flow	Injection		
	Temp	Rate					Fraction	Total	Accumulator	Spill
sec	ºF	in/sec			ft	ft		lbm/sec		
113.6	220.7	1.412	0.752	4.94	16.12	0.249	608.8	0.0	0.0	68.03
115.6	221.8	1.407	0.752	5.00	16.12	0.249	608.9	0.0	0.0	68.03
133.6	230.8	1.363	0.758	5.51	16.12	0.253	609.4	0.0	0.0	68.03
153.6	239.3	1.317	0.765	6.04	16.12	0.257	610.1	0.0	0.0	68.03
173.6	246.5	1.272	0.772	6.54	16.12	0.261	610.7	0.0	0.0	68.03
193.6	252.7	1.227	0.779	7.01	16.12	0.265	611.3	0.0	0.0	68.03
217.6	258.9	1.174	0.790	7.53	16.12	0.270	612.0	0.0	0.0	68.03
243.6	264.4	1.115	0.804	8.03	16.12	0.274	612.7	0.0	0.0	68.03
271.6	269.3	1.048	0.829	8.50	16.12	0.280	613.4	0.0	0.0	68.03
317.6	274.7	0.932	0.895	9.00	16.12	0.287	614.5	0.0	0.0	68.03
442.9	284.7	0.838	0.889	10.00	16.12	0.290	617.2	0.0	0.0	68.03

Table 2.6.3.1-33
Double Ended Cold Leg Break With Minimum ECCS Flows
Mass Balance

Time (Seconds)		.00	22.40	22.40	442.89
		Mass (Thousands lbm)			
Initial	In RCS and ACC	743.78	743.78	743.78	743.78
Added Mass	Pumped Injection	0.00	0.00	0.00	243.30
	Total Added	0.00	0.00	0.00	243.30
*** Total Available ***		743.78	743.78	743.78	987.08
Distribution	Reactor Coolant	516.19	33.03	70.65	130.79
	Accumulator	227.59	160.41	122.79	0.00
	Total Contents	743.78	193.44	193.44	130.79
Effluent	Break Flow	0.00	550.33	550.33	844.73
	ECCS Spill	0.00	0.00	0.00	0.00
	Total Effluent	0.00	550.33	550.33	844.73
*** Total Accountable ***		743.78	743.77	743.77	975.52

Table 2.6.3.1-34
Double Ended Cold Leg Break With Minimum ECCS Flows
Energy Balance

Time (Seconds)		.00	22.40	22.40	442.89
		Energy (Million Btu)			
Initial Energy	In RCS, Accumulator and Steam Generator	850.76	850.76	850.76	850.76
Added Energy	Pumped Injecti0n	.00	.00	.00	16.55
	Decay Heat	.00	6.79	6.79	53.93
	Heat From Secondary	.00	10.14	10.14	10.14
	Total Added	.00	16.93	16.93	80.62
Total Available		850.76	867.69	867.69	931.37
Distribution	Reactor Coolant	307.53	8.03	11.40	28.63
	Accumulator	20.41	14.38	11.01	.00
	Core Stored	24.79	13.13	13.13	4.67
	Primary Metal	153.93	147.42	147.42	125.00
	Secondary Metal	52.81	53.20	53.20	49.42
	Steam Generat0r	291.30	308.66	308.66	281.72
	Total Contents	850.76	544.82	544.82	489.44
Effluent	Break Flow	.00	322.28	322.28	431.08
	ECCS Spill	.00	.00	.00	.00
	Total Effluent	.00	322.28	322.28	431.08
total Accountable		850.76	867.10	867.10	920.52

Table 2.6.3.1-35
Double Ended Hot Leg Break Sequence of Events

Time (Sec)	Event Description
0.0	Break Occurs, Reactor Trip and Loss of Offsite Power Are Assumed
0.495	Compensated Pressurizer Pressure for Turbine Trip – 1889.6 psia Reached
4.7	Low-Pressurizer Pressure SI Setpoint – 1615 psia Reached - Feedwater Isolation Signal
10.5	Feedwater Isolation Valves Closed
13.7	Broken Loop Accumulator Begins Injecting Water
13.9	Intact Loop Accumulator Begins Injecting Water
23.4	End-of-Blowdown Phase
23.4	Accumulator Mass Adjustment for Refill Period
44.7	Pumped SI Begins after 40-Second Diesel Delay
56.73	Broken-Loop Accumulator Water Injection Ends
56.73	Intact-Loop Accumulator Water Injection Ends
152.25	End-of-Reflood Phase – Westinghouse Calculations End

Table 2.6.3.1-36
Double-Ended Pump Suction Break - Minimum Safeguards Sequence of Events

Time (sec)	Event Description
0.0	Break Occurs, Reactor Trip, and Loss-of-Offsite Power Are Assumed
0.677	Compensated Pressurizer Pressure Turbine Trip – 1889.6 psia Reached
5.3	Low-Pressurizer Pressure SI Setpoint – 1615 psia Reached – Feedwater Isolation Signal
10.5	Feedwater Isolation Valves Closed
16.5	Broken-Loop Accumulator Begins Injecting Water
16.7	Intact-Loop Accumulator Begins Injecting Water
25.9	End-of-Blowdown Phase
25.9	Accumulator Mass Adjustment for Refill Period
45.3	Pumped SI Begins after 40-Second Diesel Delay
51.75	Broken-Loop Accumulator Water Injection Ends
51.80	Intact-Loop Accumulator Water Injection Ends
224.2	End-of-Reflood Phase – Westinghouse Calculations End

Table 2.6.3.1-37
Double-Ended Pump Suction Break - Maximum Safeguards Sequence of Events

Time (Sec)	Event Description
0.0	Break Occurs, Reactor Trip, and Loss-of-Offsite Power Are Assumed
0.677	Compensated Pressurizer Pressure Turbine Trip – 1889.6 psia Reached
5.3	Low-Pressurizer Pressure SI Setpoint – 1615 psia Reached – Feedwater Isolation Signal
10.5	Feedwater Isolation Valves Closed
16.5	Broken-Loop Accumulator Begins Injecting Water
16.7	Intact-Loop Accumulator Begins Injecting Water
26.0	End-of-Blowdown Phase
26.0	Accumulator Mass Adjustment for Refill Period
45.3	Pumped SI Begins after 40-Second Diesel Delay
52.23	Broken-Loop Accumulator Water Injection Ends
52.33	Intact-Loop Accumulator Water Injection Ends
268.0	End-of-Reflood Phase – **Westinghouse Calculations End**

Table 2.6.3.1-38
Double-Ended Pump Suction Break with C_D=0.6 and
Minimum Safeguards Sequence of Events

Time (sec)	Event Description
0.0	Break Occurs, Reactor Trip, and Loss-of-Offsite Power Are Assumed
0.683	Compensated Pressurizer Pressure Turbine Trip – 1889.6psia Reached
5.7	Low-Pressurizer Pressure SI Setpoint – 1615 psia Reached – Feedwater Isolation Signal
10.5	Feedwater Isolation Valves Closed
18.1	Broken-Loop Accumulator Begins Injecting Water
18.2	Intact-Loop Accumulator Begins Injecting Water
28.2	End-of-Blowdown Phase
28.2	Accumulator Mass Adjustment for Refill Period
45.7	Pumped SI Begins after 40-Second Diesel Delay
53.72	Broken-Loop Accumulator Water Injection Ends
53.87	Intact-Loop Accumulator Water Injection Ends
233.72	End-of-Reflood Phase – Westinghouse Calculations End

Table 2.6.3.1-39
3.0 ft^2 Pump Suction Split Break Minimum Safeguards Sequence of Events

Time (sec)	Event Description
0.0	Break Occurs, Reactor Trip, and Loss-of-Offsite Power Are Assumed
0.697	Compensated Pressurizer Pressure Turbine Trip – 1889.6 psia Reached
6.0	Low-Pressurizer Pressure SI Setpoint – 1615 psia Reached – Feedwater Isolation Signal
10.5	Feedwater Isolation Valves Closed
26.4	Broken-Loop Accumulator Begins Injecting Water
26.8	Intact-Loop Accumulator Begins Injecting Water
38.6	End-of-Blowdown Phase
38.6	Accumulator Mass Adjustment for Refill Period
46.0	Pumped SI Begins after 40-Second Diesel Delay
66.15	Broken-Loop Accumulator Water Injection Ends
66.2	Intact-Loop Accumulator Water Injection Ends
227.59	End-of-Reflood Phase – Westinghouse Calculations End

Table 2.6.3.1-40
Double-Ended Cold Leg Break Minimum Safeguards Sequence of Events

Time (Sec)	Event Description
0.0	Break Occurs, Reactor Trip, and Loss-of-Offsite Power Are Assumed
0.662	Compensated Pressurizer Pressure Turbine Trip – 1889.6 psia Reached
5.4	Low-Pressurizer Pressure SI Setpoint – 1615 psia Reached – Feedwater Isolation Signal
10.5	Feedwater Isolation Valves Closed
10.8	Broken-Loop Accumulator Begins Injecting Water
12.7	Intact-Loop Accumulator Begins Injecting Water
22.4	End-of-Blowdown Phase
22.4	Accumulator Mass Adjustment for Refill Period
45.4	Pumped SI Begins after 40-Second Diesel Delay
40.59	Broken-Loop Accumulator Water Injection Ends
43.99	Intact-Loop Accumulator Water Injection Ends
442.89	End-of-Reflood Phase – Westinghouse Calculations End

2.6.3.2 Mass and Energy Release Analysis for Secondary System Pipe Ruptures

2.6.3.2.1 Regulatory Evaluation

DNC's review covered the energy sources that are available for release to the Containment, the mass and energy release rate calculations, and the single failure analysis performed for steam and feedwater line isolation provisions, which would limit the flow of steam or feed water to the assumed pipe rupture.

The acceptance criteria for M&E release analyses for postulated secondary system pipe ruptures are based on

- GDC-50, insofar as it requires that the margin in the design of the containment structure reflect consideration of the effect of potential energy sources that have not been included in the determination of peak conditions, the experience and experimental data available for defining accident phenomena and containment response, and the conservatism of the model and the value of input parameters.

Specific review criteria are contained in the SRP, Sections 6.2.1 and 6.2.1.4, and guidance provided in Matrix 6 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800), SRP Sections 6.2.1, Rev. 2, and 6.2.1.4, Rev. 1.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of assumptions regarding energy sources available for release to the containment and the M&E release rate calculations relative to conformance to

- GDC-50, Containment Design Basis, is described in FSAR Section 3.1.2.50.

This section of the FSAR states: "The containment structure is designed with a leakage rate shown in FSAR Table 1.3-3. The containment is designed to withstand, by a sufficient margin, loads above those that are conservatively calculated to result from a DBA as discussed in FSAR Section 6.2.1."

FSAR Section 6.2.1.4 states that "The containment receives mass and energy releases following a postulated rupture of a steam or a feedwater line. A spectrum of MSLB accidents covering different break areas and reactor operating power levels is analyzed (See FSAR Table 6.2-22)." The MSLB accident analysis results are discussed in FSAR Section 6.2.1.1.3.7. FSAR, Section 6.2.1.1.3.8 states that "The feedwater pipe break is not as severe as the main steam pipe break, since the break effluent is at a lower specific enthalpy. A feedwater pipe break analysis for containment pressure and temperature is, therefore, not performed."

NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005 defines the scope of license renewal. The M&E release transients are not within the scope of license renewal.

2.6.3.2.2 Technical Evaluation

2.6.3.2.2.1 Introduction

Steamline ruptures occurring inside the reactor Containment structure may result in significant releases of high-energy fluid to the containment environment, producing elevated containment temperatures and pressures. The magnitude of the releases following a steamline rupture is dependent upon the plant initial operating conditions and the size of the rupture, as well as the configuration of the plant steam system and the containment design. These variations make it difficult to determine the absolute worst cases for either containment pressure or temperature evaluation following a steamline break. The analysis considers a variety of postulated pipe breaks encompassing wide variations in plant operation, safety system performance, and break size in determining the MSLB M&E releases for use in containment analysis.

Other than the MSLB event, the only significant containment M&E release event caused by a secondary-side piping breach is the FLB event. The feedwater enthalpy at any power is less than the enthalpy of saturated steam at the secondary-side operating pressures. Therefore, the long-term integrated energy released following an FLB is bounded by the long-term integrated energy released following an MSLB. It is expected that the containment pressure and temperature responses to the mass and energy releases from an FLB would be bounded by the containment responses following the MSLB event.

2.6.3.2.2.2 Input Parameters and Assumptions, and Acceptance Criteria

The analysis inputs, assumptions, methods, and acceptance criteria pertaining to the MSLB M&E releases inside containment are presented in this section.

To determine the effects of plant power level and break area on the M&E releases from a ruptured steamline, spectra of both variables have been evaluated. At plant power levels of 102 percent, 70 percent, 30 percent, and 0 percent of nominal full-load NSSS power, two limiting break sizes have been defined. These break areas are defined as the following:

4. A full DER downstream of the flow restrictor in one steamline. Note that a DER is defined as a rupture in which the steam pipe is completely severed and the ends of the break fully displace from each other. The full DER represents the largest break of the main steamline producing the highest mass flowrate from the faulted-loop steam generator. A small DER with saturated steam release is less limiting than the full DER with saturated steam release, which maximizes the steam flowrate.

5. A small split rupture, the largest break that will neither generate a steamline isolation signal from the primary protection equipment nor result in water entrainment in the break effluent. Reactor protection and safety injection actuation functions are obtained from containment pressure signals.

The 16 cases included in the MPS3 analysis for the (7.0 percent) SPU Program have been chosen based on the selection of similar steamline ruptures included in the analyses presented in FSAR Section 6.2.1.4. The cases, listed in Section 2.6.3.2.2.3, have been analyzed at the uprated NSSS power. Other assumptions regarding important plant conditions and features are discussed in the following paragraphs.

2.6.3.2.2.2.1 Initial Power Level

Steamline breaks can be postulated to occur with the plant in any operating condition ranging from hot shutdown to full power. Since steam generator water mass increases with decreasing power level, breaks occurring at lower power levels will generally result in a greater total mass release to the containment. However, because of increased stored energy in the primary side of the plant, increased heat transfer in the steam generators, and additional energy generation in the fuel, the energy release to the containment from breaks postulated to occur during full-power, or near full-power, operation may be greater than for breaks occurring with the plant in a low-power, or hot-shutdown, condition. Additionally, pressure in the steam generators increases with decreasing power and has a significant influence on the initial rate of blowdown.

Because of the opposing effects on mass versus energy release for the MSLB due to a change in initial power level, a single power level cannot be specified as the worst case for either the containment pressure response or the containment temperature response. Therefore, representative power levels of 102 percent, 70 percent, 30 percent, and 0 percent of the uprated full NSSS power conditions have been investigated for MPS3 based on the information in Reference 1. Reference 1 has been reviewed and approved by the NRC for use in MSLB analysis inside containment. Additional discussion is provided in Section 2.6.3.2.2.3.

In general, the plant initial conditions are assumed to be at the nominal value corresponding to the initial power for that case, with appropriate uncertainties included. Tables 2.6.3.2-1 and 2.6.3.2-2 identify the values assumed for NSSS power, RCS pressurizer pressure, RCS vessel average temperature, RCS flowrate, pressurizer water volume, steam generator water level, steam generator temperature and pressure, and feedwater temperature corresponding to each power level analyzed. Steamline break mass and energy releases assuming an RCS average temperature at the high end of the T_{avg} window are conservative with respect to similar releases at the low end of the T_{avg} window. At the high end, there is more mass and energy available for release into containment. The thermal design flowrate has been used for the RCS flow input consistent with the assumptions documented in Reference 1. The thermal design flowrate is also consistent with other MSLB analysis assumptions related to nonstatistical treatment of uncertainties, as well as RCS thermal-hydraulic inputs.

Uncertainties on the initial conditions assumed in the analysis for the stretch power uprate program have been applied only to the RCS average temperature (+5.0°F), the steam generator water level (+12.0 percent narrow-range span), and the power fraction (+2.0 percent) at full power. Nominal values are adequate for the initial conditions associated with pressurizer pressure and pressurizer water level. Uncertainty conditions are only applied to those parameters that could increase the amount of mass or energy discharged into containment.

2.6.3.2.2.2.2 Single-Failure Assumption

In a manner consistent with the standard approach for licensing-basis analyses, various single failures have been identified and used in the spectrum of MSLB cases analyzed. One of these failures is considered as part of the containment response analysis. The postulated single failures (discussed also in Reference 1) that increase the MSLB M&E releases to containment are discussed below:

1. Failure of the MSIV in the Faulted Loop

   The main steamline isolation function is accomplished via the MSIV in each of the four steam lines. Each valve closes on an isolation signal to terminate steam flow from the associated steam generator. The main steamline rupture upstream of this valve, as postulated for the inside-containment analysis, creates a situation in which the steam generator on the faulted loop cannot be isolated, even when the MSIV successfully closes. The break location allows a continued blowdown from the faulted-loop steam generator until it is empty and all sources of main feedwater and auxiliary feedwater addition are terminated. If the faulted-loop MSIV fails to close, blowdown from more than one steam generator is terminated by the closure of the corresponding MSIV for each intact-loop steam generator. Therefore, there is no failure of a single MSIV that could cause continued blowdown from multiple steam generators.

   In addition to the continued blowdown from the faulted-loop steam generator after MSIV closure, the steam in the unisolable sections of the main steam system needs to be considered. An MSIV failure impacts the M&E releases since a failed MSIV will result in a larger unisolable steamline volume. The analytical method of addressing the main steam piping blowdown and the effect of an MSIV failure is dependent on the break type, as discussed in Section 2.6.3.2.2.3.

2. Failure of the MFIV in the Faulted Loop

   If the MFIV in the feedwater line to the faulted steam generator is assumed to fail in the open position, backup isolation is provided via the main feedwater FCV closure. The inventory between the MFIV and the FCV in the faulted loop plus any additional pumped main feedwater until FCV closure would be available to be released to containment. For MPS3, the piping volume between the MFIV and the FCV is small, and the closure time of each valve is identical. Thus, the M&E releases inside containment for the stretch power uprate program conservatively assume the failure of the MFIV in the same loop as the ruptured steamline for all MSLB cases analyzed.

3. Failure of the AFW Runout Control Function

   MPS3 has flow-limiting cavitating venturis (passive devices which are not assumed to fail) in the AFW piping. The cavitating venturi choke point limits the maximum AFW flow to any steam generator. Thus, this single failure is not applicable to the analysis of the MSLB M&E releases inside containment.

2.6.3.2.2.2.3 Main Feedwater System

The rapid depressurization that occurs following a steamline rupture typically results in large amounts of water being added to the steam generators through the main feedwater system. A rapid-closing MFIV and FCV in each of the main feedwater lines limit this effect. The feedwater addition that occurs prior to closing of the MFIV or FCV influences the steam generator blowdown in several ways. First, because the water entering the steam generator is subcooled, it lowers the steam pressure, thereby reducing the flowrate out of the break. As the steam generator pressure decreases, some of the fluid in the feedwater lines downstream of the isolation valves will flash into the steam generators, providing additional secondary fluid which may exit out of the rupture. Secondly, the increased flow causes an increase in the total heat transfer from the primary to secondary systems, resulting in greater integrated energy being released out of the break.

Following the initiation of the MSLB, assumptions are made (see Table 2.6.3.2-3) to ensure that main feedwater flow is conservatively maximized. The initial increase in feedwater flow (until fully isolated) is in response to the feedwater pump control valve opening up in response to the steam flow/feedwater flow mismatch or the decreasing steam generator water level, as well as due to a lower backpressure on the feedwater pump as a result of the depressurizing steam generator. This maximizes the total mass addition prior to feedwater isolation. The feedwater isolation response time, following the safety injection signal, is assumed to be a total of 7 seconds, accounting for delays associated with signal processing plus MFIV stroke time. For the circumstance in which the MFIV in the faulted loop fails to close, there is no effect on the feedwater isolation response time since the total delay for the FCV closure is also 7 seconds.

Following feedwater isolation, as the steam generator pressure decreases, some of the fluid in the feedwater lines downstream of the isolation or control valve may flash to steam if the feedwater temperature exceeds the saturation temperature. This unisolable feedwater line volume is an additional source of fluid that can increase the mass discharged out of the break. The unisolable volume in the feedwater lines is maximized for the faulted loop. The feedwater line piping volume available for steam flashing in this analysis is shown in Table 2.6.3.2-3.

Steamline break mass and energy releases assuming a main feedwater temperature at the high end of the feedwater temperature window are conservative with respect to similar releases at the low end of the feedwater temperature window. At the high end, there is more energy available for release into containment.

2.6.3.2.2.2.4 Auxiliary Feedwater System

Generally, within the first minute following a steamline break, the AFW system is initiated on any one of several protection system signals. Addition of AFW to the steam generators will increase the secondary mass available for release to containment as well as increase the heat transferred to the secondary fluid. The AFW flow to the faulted and intact steam generators has been assumed to be a function of the backpressure on the auxiliary feedwater pumps as a result of the depressurizing steam generator in the MSLB analysis inside containment. Cavitating venturis in each of the AFW supply lines to the steam generators have been assumed to limit the maximum flow.

The volume of the AFW piping is minimized. Purging of AFW piping is not assumed since a minimum volume permits colder AFW to be injected into the steam generator rather than any hotter auxiliary feedwater resident in the piping. The more dense injected AFW causes a greater mass addition to the faulted-loop steam generator than if the resident auxiliary feedwater had to be purged prior to the flow of AFW into the steam generator. AFW flow to the faulted-loop steam generator has been assumed, up until the time of operator action at 30 minutes after event initiation, to isolate the flow to the steam generator near the break location. Auxiliary feedwater system assumptions that have been used in the analysis are presented in Table 2.6.3.2-3.

2.6.3.2.2.2.5 Steam Generator Fluid Mass

A maximum initial steam generator mass in the faulted-loop steam generator has been used in all of the analyzed cases. The use of a high faulted-loop initial steam generator mass maximizes the steam generator inventory available for release to containment. The initial mass has been calculated as the value corresponding to the programmed level +12.0 percent narrow-range span and assuming 0 percent tube plugging, plus a mass uncertainty. This assumption is conservative with respect to the RCS cooldown through the faulted-loop steam generator resulting from the steamline break.

2.6.3.2.2.2.6 Steam Generator Reverse Heat Transfer

Once the steamline isolation is complete, the steam generators in the intact loops may become sources of energy that can be transferred to the steam generator with the broken steamline. This energy transfer occurs via the primary coolant. As the primary plant cools, the temperature of the coolant flowing in the steam generator tubes could drop below the temperature of the secondary fluid in the intact steam generators, resulting in energy being returned to the primary coolant. This energy is then available to be transferred to the steam generator with the broken steamline. When applicable, the effects of reverse steam generator heat transfer are included in the results.

2.6.3.2.2.2.7 Break Flow Model

Piping discharge resistances are not included in the calculation of the releases resulting from the steamline ruptures (Moody Curve for an $f(\ell / D) = 0$ is used.) This is consistent with the expectations of the NRC as presented in Section 6.2.1.4 of the Standard Review Plan.

The full DER representing the largest break of the main steamline producing the highest mass flowrate from the faulted-loop steam generator has been analyzed both with entrainment in the break effluent and with no entrainment (saturated steam). The entrainment model for the MSLB M&E analysis is discussed in Reference 1 and 2 and has been applied at each initial power for the MPS3 Model F steam generator design. When assumed, entrainment in the effluent is from only the SG in the faulted loop. The no entrainment input is a conservative assumption that maximizes the energy release into containment.

2.6.3.2.2.2.8 Steamline Volume Blowdown

The contribution from the secondary plant steam piping is included in the M&E release calculations. The flowrate is determined using the Moody correlation, the pipe cross-sectional area, and the initial steam pressure. This blowdown is calculated only for the full DER steamline break. A conservative steam piping volume of 10,111 ft^3 is used in this blowdown calculation representing the main steam piping from the steam generators up to and including the MSR and the main turbine throttle valve.

For the split-rupture steamline break, the unisolable steam mass in the piping is included as part of the initial inventory in the faulted-loop steam generator since the break is not large enough to cause a sudden decompression of the piping. The steamline break cases that do not assume a failure of the MSIV in the faulted loop use a value of 947 ft^3 for the unisolable volume, which is the maximum value of all four steam lines. The MSLB cases that assume a failure of the MSIV in the faulted loop use a greater value (8,074 ft^3) for the unisolable volume post blowdown.

The analytical method of addressing the main steamline piping blowdown and the effect of an MSIV failure or no MSIV failure is discussed in Section 2.6.3.2.2.3.

2.6.3.2.2.2.9 Main Steamline Isolation

Steamline isolation is assumed in all four loops to terminate the blowdown from the three intact steam generators. A delay time of 12 seconds, accounting for delays associated with signal processing plus MSIV stroke time, with unrestricted steam flow through the valve during the valve stroke, has been assumed.

2.6.3.2.2.2.10 Protection System Actuations

The protection systems available to mitigate the effects of an MSLB inside containment include reactor trip, safety injection, steamline isolation, and main feedwater isolation. the protection system actuation signals, associated setpoints, and delays that have been modeled in the analysis are identified in Table 2.6.3.2-4. The setpoints used are conservative values with respect to the plant-specific values delineated in the Technical Specifications. the specific functions credited in the MPS3 plant-specific analysis are documented in Section 2.6.3.2.2.4.

2.6.3.2.2.2.11 Safety Injection System

Minimum SIS flowrates corresponding to the failure of one SIS train have been assumed in this analysis. (This is in addition to the MSLB-related single failures noted in Section 2.6.3.2.2.2.) A minimum SI flow is conservative since the reduced boron addition maximizes a return to power resulting from the RCS cooldown. The higher power generation increases heat transfer to the secondary side, maximizing steam flow out of the break.

The SIS flowrates for the MSLB M&E analysis assume that one charging pump and one safety injection pump are available for RCS cold-leg injection. The minimum SIS flowrates that have been modeled in the analysis are presented in Table 2.6.3.2-5. From Table 2.6.3.2-4, the delay time to achieve full SI flow is 31 seconds for this analysis with offsite power available. A coincident loss of offsite power is not assumed for the analysis of the MSLB inside containment since the M&E releases would be reduced due to the loss of forced reactor coolant flow, resulting in less primary-to-secondary heat transfer.

2.6.3.2.2.2.12 Reactor Coolant System Metal Heat Capacity

As the primary side of the plant cools, the temperature of the reactor coolant drops below the temperature of the reactor coolant piping, the reactor vessel, the reactor coolant pumps, and the steam generator thick-metal mass and tubing. As this occurs, the heat stored in the metal is available to be transferred via the primary coolant to the steam generator with the broken line. The effects of this RCS metal heat are included in the results using conservative thick-metal masses and heat transfer coefficients.

2.6.3.2.2.2.13 Core Decay Heat

Core decay heat generation assumed in calculating the steamline break mass and energy releases is based on the 1979 ANS Decay Heat + 2 model (Reference 3). The existing analysis assumed the use of the 1971 standard (+20 percent uncertainty) for the decay heat. The assumption of using the 1979 version represents a deviation from the current licensing-basis analysis MSLB M&E releases for MPS3. The 1979 ANS decay heat model has previously been assumed for the spectrum of non-LOCA transients for MPS3. This is the first application of the more recent decay heat model for the plant-specific analysis of the MSLB M&E releases inside containment.

2.6.3.2.2.2.14 Rod Control

The rod control system is conservatively assumed to be in manual operation for all MSLB analyses. Assuming that the reactor is in manual rod control allows for a greater RCS cooldown prior to the reactor trip signal, which maximizes the reactivity feedback at end-of-cycle conditions and produces a greater post-trip power increase.

2.6.3.2.2.2.15 Core Reactivity Coefficients

Conservative core reactivity coefficients corresponding to end-of-cycle conditions are used to maximize the reactivity feedback effects resulting from the increase in heat transfer to the secondary side and the subsequent primary coolant cooldown following the steamline break. The reactivity feedback causes a return to power within the core which generates additional heat, raising the temperature of the coolant. The higher primary-side temperature increases the heat transfer to the secondary side, causing an increase in the energy and mass flowrates out of the break.

2.6.3.2.2.2.16 Acceptance Criteria

The main steamline break is classified as an ANS Condition IV event, an infrequent fault. The acceptance criteria associated with the MSLB event resulting in M&E releases inside containment is based on an analysis that provides sufficient conservatism to show that the containment design margin is maintained. The specific criteria applicable to this analysis are related to the assumptions regarding power level, stored energy, the break flow model, main and auxiliary feedwater flow, steamline and feedwater isolation, and single failure, such that the containment peak pressure and temperature are maximized. These analysis assumptions have been included in this MSLB M&E release analysis as discussed in Reference 1.

2.6.3.2.2.3 Description of Analyses and Evaluations

The system transient that provides the break flows and enthalpies of the steam release from the MSLB inside containment has been analyzed with the LOFTRAN (Reference 4) computer code. Blowdown mass and energy releases determined using LOFTRAN include the effects of core power generation, main and auxiliary feedwater additions, engineered safeguards systems, reactor coolant system thick-metal heat storage, including steam generator thick-metal mass and tubing, and reverse steam generator heat transfer.

The existing MSLB M&E analysis inside containment was performed using the MARVEL code as documented in WCAP-8822 (Reference 1). The use of the LOFTRAN code for the analysis of the MSLB M&E releases is documented in Supplement 1 of WCAP-8822 and has been reviewed and approved by the NRC for this application. The LOFTRAN code has been utilized previously for the MPS3 licensing-basis safety analyses.

The following licensing-basis cases of the MSLB inside containment have been analyzed at the noted conditions for the Stretch Power Uprate Program.

- 102 percent power, full double-ended (1.4 ft^2) rupture – MSIV and MFIV single failures – no entrainment
- 102 percent power, full double-ended (1.4 ft^2) rupture – MSIV and MFIV single failures – entrainment in the faulted-loop SG
- 102 percent power, 0.653 ft^2 split rupture – MFIV single failure
- 102 percent power, 0.653 ft^2 split rupture – MSIV and MFIV single failures
- 70 percent power, full double-ended (1.4 ft^2) rupture – MSIV and MFIV single failures – no entrainment
- 70 percent power, full double-ended (1.4 ft^2) rupture – MSIV and MFIV single failures – entrainment in the faulted-loop SG
- 70 percent power, 0.659 ft^2 split rupture at 70 percent power – MFIV single failure
- 70 percent power, 0.659 ft^2 split rupture at 70 percent power – MSIV and MFIV single failures
- 30 percent power, full double-ended (1.4 ft^2) rupture – MSIV and MFIV single failures – no entrainment
- 30 percent power, full double-ended (1.4 ft^2) rupture – MSIV and MFIV single failures – entrainment in the faulted-loop SG
- 30 percent power, 0.671 ft^2 split rupture – MFIV single failure
- 30 percent power, 0.671 ft^2 split rupture – MSIV and MFIV single failures

- 0 percent power, full double-ended (1.4 ft^2) rupture – MSIV and MFIV single failures – no entrainment
- 0 percent power, full double-ended (1.4 ft^2) rupture – MSIV and MFIV single failures – entrainment in the faulted-loop SG
- 0 percent power, 0.512 ft^2 split rupture – MFIV single failure
- 0 percent power, 0.512 ft^2 split rupture – MSIV and MFIV single failures

For the double-ended rupture cases, the forward-flow cross-sectional area from the faulted-loop steam generator is limited by the integral flow restrictor area of 1.4 ft^2, which is less than the actual area of 4.12 ft^2 for the reverse-direction cross-sectional flow area of the piping inside containment. The cross-sectional area of the steam piping at this location is nearly as large as the sum of the flow restrictors in the intact-loop steam generators. Therefore, the assumption is made that the larger cross-sectional area of the ruptured steamline expels steam faster than the smaller cross-sectional area of the intact-loop steam generator flow restrictors can fill it. Thus, the blowdown of the initial steam in the steamline header piping is modeled in the first few seconds of the event, followed by the reverse-flow blowdown from the intact-loop steam generators until MSIV closure. The initial reverse-flow blowdown is discussed in Section 2.6.3.2.2.2.8, Steamline Volume Blowdown, and provided in Table 2.6.3.2-6. The rate of the M&E releases from the steam header piping is a function of the initial pressure in the main steam system, which increases with decreasing power. At the time of MSIV closure, the steam flow from the intact-loop steam generators is terminated, but it is assumed that all steam that has exited the steam generator prior to steamline isolation is released through the break. This is consistent with the Reference 1 methodology and reflects no differentiation between the effect of an MSIV failure and no MSIV failure for the full DER MSLB cases.

The full DER represents the break producing the highest mass flowrate from the faulted-loop steam generator. Smaller DER break sizes are represented by a reduction in the initial steam blowdown rate at the time of the break. Therefore, no other DER break sizes have been considered other than the full DER.

For the split-rupture cases, the break area is smaller than the area of a single integral flow restrictor. The flowrate from all steam generators prior to MSIV closure and the flowrate from a single steam generator after MSIV closure supply the steam flow to the break. The steam in the unisolable portion of the steamline does not affect the blowdown until the time of steam generator dry-out, when the flowrate from the steam generator would decrease below the critical flowrate out of the break. At this point, the additional steam in the piping begins to have an effect on break flowrate until the steamline piping is empty. To model this effect in LOFTRAN, the mass of the unisolable steam in the steamline is added to the initial mass of the faulted steam generator. This accurately reflects both the total mass and energy that is released from the break and the timing of the effect of the unisolable steamline volume on the blowdown. When all MSIVs are credited to successfully close, the unisolable steamline volume is 947 ft^3. A failure of the MSIV on the faulted loop increases the unisolable steamline volume to a larger value of 8,074 ft^3 for the post blowdown releases.

For split ruptures, the largest cross-sectional area that does not produces a steamline isolation signal from the primary protection equipment nor results in water entrainment in the break effluent was determined as discussed in Reference 1. These areas were determined based on the MPS3 plant-specific values for the secondary-side protection system setpoints incorporated into the LOFTRAN NSSS model.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the mass and energy release for postulated secondary system piping ruptures analysis. As stated in Section 2.6.3.2.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.6.3.2.2.4 Results

Using the MSLB analysis methodology documented in Reference 1 as a basis, including MPS3 plant-specific parameter changes associated with the stretch power uprate program, the M&E release rates for each of the steamline break cases noted in Section 2.6.3.2.2.3 have been developed for use in containment pressure and temperature response analyses. Table 2.6.3.2-7 provides the sequence of events for each of the 16 steamline break cases analyzed for MPS3 at the uprated NSSS power.

For the double-ended rupture MSLB at all power levels, the first protection system signal actuated is Low Steamline Pressure (2-of-3 channels per loop, lead/lag compensated in each channel) in any loop that initiates steamline isolation and actuates the safety injection signal; the safety injection signal produces a reactor trip signal. Feedwater system isolation and AFW actuation also occur as a result of the safety injection signal. For conservatism, the SIS actuation on Low Steamline Pressure SI has not been credited. In the analysis, SIS is actuated upon receipt of the Low Pressurizer Pressure SI signal (2-of-4 channels).

For the split-rupture steamline breaks at all power levels, no mitigation signal is received from any secondary-side signal produced by the primary protection equipment. The first protection system signals actuated are assumed to be the High-1 Containment Pressure (2-of-3 channels) and the High-2 Containment Pressure (2-of-3 channels), which have the same setpoint value for actuation of the mitigation functions. The High-1 Containment Pressure signal initiates safety injection; the safety injection signal produces a reactor trip signal. Feedwater system isolation and AFW actuation occur as a result of the safety injection signal. Steamline isolation is initiated following receipt of the High-2 Containment Pressure signal.

The turbine stop valve is assumed to close instantly following the reactor trip signal; the delay time used in the MSLB M&E releases inside containment is 0.0 seconds. This assumption maximizes the steam available for release out of the break.

2.6.3.2.3 Conclusion

DNC has reviewed the M&E release assessment for the postulated secondary system pipe ruptures and finds that the analyses adequately address the effects of the proposed SPU. Based on this, DNC concludes that the analysis meets the MPS3 current licensing-basis requirements with respect to GDC-50 for ensuring that the analysis is conservative (i.e., the analysis includes sufficient margin). Therefore, DNC finds the proposed SPU acceptable with respect to M&E releases for postulated secondary system pipe rupture.

2.6.3.2.4 References

1. WCAP-8822 (Proprietary) and WCAP-8860 (Nonproprietary), Mass and Energy Releases Following a Steam Line Rupture, September 1976; WCAP-8822-S1-P-A (Proprietary) and WCAP-8860-S1-A (Nonproprietary), Supplement 1 – Calculations of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture, September 1986; WCAP-8822-S2-P-A (Proprietary) and WCAP-8860-S2-A (Nonproprietary), Supplement 2 – Impact of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture for Dry and Subatmospheric Containment Designs, September 1986.

2. WCAP-8821-P-A (Proprietary) and WCAP-8859-A (Nonproprietary), TRANFLO Steam Generator Code Description, June 2001.

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

4. WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), LOFTRAN Code Description, April 1984.

5. NEU-07-11, MPS3 SPUP Steamline Break Mass & Energy Releases Inside Containment Technical Report, January 22, 2007.

Table 2.6.3.2-1 Nominal and Initial Plant Parameters for Stretch Power Uprate(1) MSLB M&E Releases Inside Containment

Plant Parameter	Nominal	Full Power Initial
NSSS Power, Mwt	3666	3739
Core Power, Mwt	3650	not an input
RCS Flowrate (total), gpm (Thermal Design Flow)	363,200	363,200
Pressurizer Pressure, psia	2250	2250
Pressurizer Water Volume,% span(2)	60.0	60.0
RCS Vessel Average Temperature, °F	589.5	594.5
Steam Generator(3)		
Steam Temperature, °F	542.6	546.9
Steam Pressure, psia	984	1019
Feedwater Temperature, °F	445.3	445.3
Water Level,% narrow-range span	50.2	62.2
Zero-Load Temperature, °F	557	557

Notes:

(1) Noted values correspond to plant conditions defined by 0% steam generator tube plugging and the high end of the RCS T_{avg} window, initial temperature includes applicable calorimetric uncertainties and bias.

(2) The pressurizer water volume does not reflect the proposed pressurizer water level program of 64% at full power. However, the difference is not significant.

(3) Steam generator performance data used in the analysis is conservatively high for steam temperature and pressure.

Table 2.6.3.2-2 Part-Power Initial-Condition Plant Parameters for Stretch Power Uprate(1) MSLB M&E Releases Inside Containment

Initial Conditions	**Power Level (%)**		
Parameter	**70**	**30**	**0**
NSSS Power, Mwt	2566	1100	37
RCS Vessel Average Temperature, °F	584.75	571.75	557.0
RCS Flowrate, gpm (Thermal Design Flow)	363,200	363,200	363,200
Pressurizer Pressure, psia	2250	2250	2250
Pressurizer Water Volume,% span(2)	49.5	35.5	25.0
Feedwater Temperature, °F	407	343	100
Steam Temperature, °F	551.6	557.3	556.5
SG Pressure, psia(3)	1059	1109	1102
SG Water Level,% NRS	62.2	62.2	62.2

Notes:

2. Noted values correspond to plant conditions defined by 0% steam generator tube plugging and the high end of the RCS T_{avg} window, temperatures includes applicable calorimetric uncertainties and/or bias.
3. The pressurizer water volume does not reflect the proposed pressurizer water level program of 64% at full power. However, the difference is not significant.
4. The noted SG pressures are determined at the steady-state conditions defined by the RCS average temperatures, including applicable uncertainties and/or bias.

Table 2.6.3.2-3
Main and Auxiliary Feedwater System Assumptions for Stretch Power Uprate MSLB M&E Releases Inside Containment

Parameter	Analysis Assumption
Main Feedwater System	
Flowrate - double-ended ruptures @ all powers (until main feedwater isolation)	Feedwater flow based on system performance as a function of SG pressure.
Flowrate - split ruptures @ all powers (until main feedwater isolation)	Feedwater flow equals steam flow.
Unisolable volume from SG nozzle to FCV assuming a single failure of the MFIV (faulted loop), ft^3	438
Auxiliary Feedwater System	
Flowrate to all steam generators	Maximum flow to each SG is 299 gpm. The actual data used is a function of SG pressure.
Temperature (maximum value), °F Piping purge volume (minimized value), ft^3	120 1.0
Actuation delay time, seconds	0

Table 2.6.3.2-4 Protection System Actuation Signals and Safety System Setpoints for Stretch Power Uprate MSLB M&E Releases Inside Containment

Actuation Signal	Safety Analysis Setpoint
Reactor Trip	
2/4 Low Pressurizer Pressure, psia	1860
Delay, seconds	2
Delay following the Safety Injection Signal, seconds	2
Safety Injection	
2/4 Low Pressurizer Pressure, psia	1700
Delay, seconds	31
2/3 Low Steamline Pressure in any loop, psia	624.7
Dynamic compensation lead, seconds	50
Dynamic compensation lag, seconds	5
Delay, seconds	31
2/3 High-1 Containment Pressure	see note 1
Delay, seconds	31
Steamline Isolation	
2/3 Low Steamline Pressure in any loop, psia	624.7
Dynamic compensation lead, seconds	50
Dynamic compensation lag, seconds	5
Delay, seconds	12
2/3 High-2 Containment Pressure	see note 1
Delay, seconds	12
Feedwater Isolation and Auxiliary Feedwater Initiation	
Delay following the Safety Injection Signal	
Feedwater Isolation, seconds	7
Auxiliary Feedwater Initiation, seconds	see Table 2.6.3.2.2-3
Turbine Trip	
Delay following the Reactor Trip Signal, seconds	0

Notes:
1. The time that the High-1 Containment Pressure and High-2 Containment Pressure setpoint was reached was determined in the containment response analysis. A bounding time for each split-break case was used as the input to this analysis.

Table 2.6.3.2-5 Safety Injection System Flowrates for Stretch Power Uprate MSLB M&E Releases Inside Containment

RCS Pressure (psia)	SIS Flowrate (lbm/sec)
614.7	107.96
1014.7	82.97
1214.7	63.26
1414.7	32.92
1614.7	28.92
1814.7	23.75
2014.7	18.41
2214.7	14.13
2414.7	10.45
2482.7	0.0

Table 2.6.3.2-6 Mass and Energy Flowrates for Steam Piping Reverse Flow Blowdown – Applicable to the DER MSLBs Inside Containment

Power Level	102%	70%	30%	0%
Steam Mass Flowrate (lbm/sec)	8,549.9	8,997.5	9,448.4	9,448.4
Steam Enthalpy (Btu/lbm)	1193.0	1191.3	1189.3	1189.4
Duration of Blowdown (sec)	2.65	2.64	2.66	2.65

Table 2.6.3.2-7
Transient Summary for the Spectrum of MSLB M&E Releases Inside Containment

Initial Power, Single Failure, Entrainment	Break Type	Reactor Trip Signal	Rod Motion (sec)	AFW Initiation/ Termination (sec)	Main Feedwater Isolation, Faulted SG (sec)	Steamline Isolation (sec) (1) (2)	Faulted SG Dryout (sec)
102%, MSIV/MFIV, no entrainment	DER	SI-LSP	2.73	0.73/1800	7.73	12.73	1802
102%, MSIV/MFIV, entrainment	DER	SI-LSP	2.73	0.73/1800	7.73	12.73	1802
102%, MFIV, no entrainment	Split	High-1	51	49/1800	56	61	1812
102%, MSIV/MFIV, no entrainment	Split	High-1	51	49/1800	56	61	1812
70%, MSIV/MFIV, no entrainment	DER	SI-LSP	2.61	0.61/1800	7.61	12.61	1802
70%, MSIV/MFIV, entrainment	DER	SI-LSP	2.61	0.61/1800	7.61	12.61	1802
70%, MFIV, no entrainment	Split	High-1	48	46/1800	53	58	1812
70%, MSIV/MFIV, no entrainment	Split	High-1	48	46/1800	53	58	1812
30%, MSIV/MFIV, no entrainment	DER	SI-LSP	2.56	0.56/1800	7.56	12.56	1802

Table 2.6.3.2-7
Transient Summary for the Spectrum of MSLB M&E Releases Inside Containment

Initial Power, Single Failure, Entrainment	Break Type	Reactor Trip Signal	Rod Motion (sec)	AFW Initiation/ Termination (sec)	Main Feedwater Isolation, Faulted SG (sec)	Steamline Isolation (sec) (1) (2)	Faulted SG Dryout (sec)
30%, MSIV/MFIV, entrainment	DER	SI-LSP	2.56	0.56/1800	7.56	12.56	1802
30%, MFIV, no entrainment	split	High-1	44	42/1800	49	54	1814
30%, MSIV/MFIV, no entrainment	split	High-1	44	42/1800	49	54	1814
0%, MSIV/MFIV, no entrainment	DER	SI-LSP	2.47	0.47/1800	7.47	12.47	1802
0%, MSIV/MFIV, entrainment	DER	SI-LSP	2.47	0.47/1800	7.47	12.47	1802
0%, MFIV, no entrainment	split	High-1	63	0/1800	68	73	1813
0%, MSIV/MFIV, no entrainment	split	High-1	63	0/1800	68	73	1813

Key SI – safety injection
LSP – low steam pressure
High-1 – containment high pressure

1. For the MSIV-failure cases, steamline isolation occurs only in the 3 unfaulted steam lines; there is no closure of the MSIV in the faulted steamline.
2. For the split breaks, the signal for steamline isolation is High-2 – containment pressure.

2.6.4 Combustible Gas Control in Containment

2.6.4.1 Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the Containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excessive hydrogen is generated, it may form a combustible mixture in the containment atmosphere.

The acceptance criteria presented in RS-001 for combustible gas control in containment are based on

1. 10 CFR 50.44, insofar as it requires that plants be provided with the capability for controlling combustible gas concentrations in the containment atmosphere.
2. GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units, unless it can be shown that sharing will not significantly impair their ability to perform their safety functions.
3. GDC-41, insofar as it requires that systems be provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure that containment integrity is maintained.
4. GDC-42, insofar as it requires that systems required by GDC-41 be designed to permit appropriate periodic inspection.
5. GDC-43, insofar as it requires that systems required by GDC-41 be designed to permit appropriate periodic testing.

Specific review criteria are contained in SRP Section 6.2.5 and guidance provided in Matrix 6 of RS-001.

The Commission eliminated the hydrogen release associated with a design basis LOCA from 10 CFR 50.44 and the associated requirements that established the need for the hydrogen recombiners and the backup hydrogen vent and purge systems.

Thus, the DNC review primarily focused on any impact that the proposed SPU may have on the capability to meet the remaining requirements of 10 CFR 50.44 that pertain to MPS3. 10 CFR 50.44(b)(1) requires that MPS3 continue to possess the capability to ensure a mixed containment atmosphere, and 10 CFR 50.44(b)(4)(ii) requires that MPS3 continue to possess the capability to monitor hydrogen in containment.

MPS3 Current Licensing Basis

By letter dated September 8, 2004, as supplemented by letter dated May 23, 2005, DNC submitted a request for changes to the Millstone Power Station, Unit Nos. 2 and 3, Technical Specifications. DNC proposed to delete the Technical Specification requirements associated with hydrogen recombiners and hydrogen monitors. The NRC approved the license amendment request on June 25, 2005.

The NRC approved Technical Specification changes that eliminated the need for hydrogen recombiners and conformance to GDC-41, GDC-42, GDC-43, and GDC-5 with respect to the containment combustible gas control system.

10 CFR 50.44(b)(1) requires that the unit possess the capability to ensure a mixed atmosphere. FSAR Section 6.2.5.3 states that mixing of hydrogen in the containment following a LOCA results from three mechanisms: 1) momentum transfer from the fluid jet exiting the break; 2) forced and natural convection flows within the containment atmosphere; and 3) molecular diffusion. These mechanisms work together to enhance mixing within the Containment to provide a homogeneous gas mixture and prevent local accumulation of hydrogen. FSAR Section 6.2.5.3 provides a brief discussion of each mixing mechanism.

10 CFR 50.44(b)(4)(ii) states that: “Equipment must be provided for monitoring hydrogen in the containment. Equipment for monitoring hydrogen must be functional, reliable, and capable of continuously measuring the concentration of hydrogen in the containment atmosphere following a significant beyond design-basis accident for accident management, including emergency planning.”

As stated in the DNC letter dated September 8, 2004, and the NRC’s Safety Evaluation Report provided to support the License Amendment, DNC has maintained a hydrogen monitoring system capable of diagnosing beyond design-basis accidents. However, the components necessary to monitor hydrogen no longer need to be classified as safety-related as previously recommended by RG 1.97.

Portions of the hydrogen recombiner system were evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.3B.3.30 and 3.3B.2.3.29 are applicable to the hydrogen recombiner system.

2.6.4.2 Technical Evaluation

The SPU has no impact on the fundamental mixing mechanisms identified in FSAR Section 6.2.5.3 or the capability of the hydrogen monitoring system to diagnose beyond design-basis events.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Portions of the fission product control systems are within the scope of license renewal. Aging management programs are addressed in the License Renewal SER Section 3.3B.2.3.29. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating at SPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.6.4.3 Conclusion

DNC concludes that, based on the license amendment approved by the NRC on June 29, 2005, the containment combustible gas control system and its components are no longer classified as an engineered safety feature or safety-related. DNC further concludes that post-LOCA hydrogen generation at the proposed SPU conditions need not be further evaluated.

MPS3 continues to comply with the requirements of 10 CFR 50.44. The SPU has no impact on the fundamental mixing mechanisms identified in FSAR Section 6.2.5.3 or the capability of the hydrogen monitoring system to diagnose beyond design-basis events.

Therefore, DNC finds the proposed SPU acceptable with respect to combustible gas control in containment.

2.6.4.4 References

1. Letter from V. Nerses (NRC) to D. A. Christian (DNC), “Millstone Power Station, Unit Nos. 2 and 3-Issuance of Amendment Re: Elimination of Requirements for Hydrogen Recombiners and Hydrogen Monitors Using the Consolidated Line Item Improvement Process (TAC NOS. MC4389 and MC4390),” dated June 29, 2005.

2. Letter from L. N. Hartz (Dominion and DNC) to U.S. Nuclear Regulatory Commission, “Virginia Electric and Power Company, Dominion Nuclear Connecticut, Inc., Surry Power Station Units 1 and 2, North Anna Power Station Units 1 and 2, Millstone Power Station Units 2 and 3, Application for Technical Specification Improvement to Eliminate Requirements for Hydrogen Recombiners and Hydrogen Monitors Using the Consolidated Line Item Improvement Process,” dated September 8, 2004.

3. Letter from E. S. Grecheck (DNC) to U.S. Nuclear Regulatory Commission, “Dominion Nuclear Connecticut, Inc., Millstone Power Station Units 2 and 3, Modification of Request for Implementation Regarding License Amendment Request to Eliminate Requirements for Hydrogen Recombiners,” dated May 23, 2005.

2.6.5 Containment Heat Removal (RSS Pump NPSH Analysis)

2.6.5.1 Regulatory Evaluation

Spray systems are provided to remove heat from the containment atmosphere and from the water in the containment sump. DNC's review focused on: (1) the effects of the proposed SPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps; (2) the analyses of the heat removal capabilities of the spray water system and the heat exchangers for RSS; and 3) the containment sump pH.

The acceptance criteria for containment heat removal are based on:

- GDC-38, insofar as it requires that the containment heat removal system be capable of rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels.

Specific review criteria are contained in the SRP Section 6.2.2 and Matrix 6 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants," SRP 6.2.2, Rev. 3.

As noted in the FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to:

- GDC-38, Containment Heat Removal, is described in FSAR Section 3.1.2.38.

  Heat is removed from the containment structure following a LOCA by the containment depressurization systems, which consist of the QSS and RSS (FSAR Section 6.2.2).

The containment heat removal systems are designed to reduce the containment pressure following a break in either the primary or secondary piping system inside the containment. Heat is transferred from the containment atmosphere to the QSS and RSS water. Heat is transferred from the containment to the service water system via the RSS heat exchangers.

The functional performance assumptions for the containment heat removal systems (QSS and RSS) are inputs to the containment accident analyses. The impact of the SPU on the containment analysis is discussed in Section 2.6.1.

The QSS consists of two parallel flow paths that provide quench spray to opposite sides of the two spray headers. Each flow path consists of one spray pump and associated piping and valves that draw water independently from the RWST. The QSS pumps start on a CDA signal. The QSS is capable of operating continuously until the RWST is nearly emptied (nominal QSS auto-trip level). Each QSS pump is capable of supplying approximately 4,000 gallons per minute of borated water solution to the two 360° QSS headers with a spray effectiveness consistent with the accident analysis assumptions. The system meets the redundancy requirements of an engineered safety feature and will satisfy the system performance requirements despite the most limiting single-active failure in the short term or the most limiting single-active or passive failure in the long term. (FSAR Sections 6.2.2.2 and 6.5.2.2)

Each of the two RSS subsystems consists of two RSS coolers and pumps that share two spray headers with a spray effectiveness consistent with the accident analyses. The four RSS pumps take suction from a common containment sump, and provide cooled flow to containment recirculation, safety injection, and charging. The NPSH available to RSS pumps is designed to meet RG 1.1 (as clarified by SRP 6.2.2) and RG 1.82, Rev. 3.

In a letter dated September 13, 2005, and supplemented by letters dated June 13, and August 14, 2006, DNC proposed to start the RSS pumps on receipt of a RWST low-low signal after receipt of a CDA signal. The previous licensing basis utilized a timer to actuate the RSS pumps after receipt of a CDA signal. The NRC approved the license amendment request on September 20, 2006. DNC implemented the License Amendment during the 2007 spring outage for MPS3.

Two risers feed each RSS spray header, with each riser running from one of the RSS coolers in each of the subsystems. The two pumps in each subsystem are connected to different spray headers, but they are both connected to the same emergency bus. Failure of one emergency bus does not prevent delivery of sufficient containment recirculation flow. The design of the containment recirculation system is sufficiently independent and redundant so that an active failure in the recirculation spray mode, cold leg recirculation mode, or hot leg recirculation mode of the ECCS has no effect on its ability to perform its engineered safety function. (FSAR Section 6.2.2.2)

The RSS transfers heat from inside the containment structure via the RSS coolers to the service water system. The service water flow to each cooler is approximately 5,900 gpm (5,400 gpm is assumed for containment analysis). The heat transfer duty for the coolers varies throughout the DBA. This is due to the reduction in the temperature of the water on the containment structure floor. The service water system is discussed in Section 2.5.4.2.

The four RSS pumps are located adjacent to the containment structure at an elevation sufficiently below the containment structure sump to ensure an adequate available NPSH. Each RSS has a design flow of approximately 3,950 gpm.

In a letter dated June 13, 2006, DNC identified the basis for establishing the minimum water level in the containment sump for the start of the RSS pumps. Implementation of the RSS pump start on RWST low-low level signal results in a minimum water level of approximately 52 inches above the general floor level of –24 ft 6 inches.

Rising sump water due to a LOCA will dissolve TSP stored in twelve porous baskets located on elevation (-)24'-6" of the containment structure. The amount of TSP is sufficient to raise the final pH of the containment sump water to above 7.0, considering the maximum total volume of borated water that could become available in the sump following a LOCA. The dissolving characteristics of the TSP assure its dissolution at a rate equal or faster than the rate of its submergence in the rising water. The mixing action of the RSS pumps assures evenly distributed pH throughout the flooded and sprayed areas. (FSAR Section 6.2.2.2)

The minimum expected ultimate sump pH is identified as 7.0 in FSAR Table 6.1-2. FSAR Figure 6.5-1 establishes the minimum containment sump pH following a LOCA. It shows that the containment sump pH will be greater than 7.0 for the entire period that the RSS pumps are assumed to operate post-LOCA. Per the DNC letter dated September 13, 2005, the RSS pumps are assumed to start at 2530 seconds post-LOCA, and are effective from 2710 seconds post-LOCA to 30 days post-LOCA.

The QSS and RSS were evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838 Sections: 1) 2.3B.2.2 and 3.2B.2.3.2 are applicable to the QSS; and 2) 2.3B.2.1 and 3.2B.2.3.1 are applicable to the RSS.

2.6.5.2 Technical Evaluation

2.6.5.2.1 Containment Heat Removal and Depressurization

The SPU increases the heat available to be released into containment. Thus, in the event of a LOCA, there would be additional heat loads imposed on the QSS, RSS, and service water system.

Section 2.6.1 provides the containment response analysis that demonstrates the acceptability of the containment heat removal systems to mitigate the consequence of a spectrum of large LOCA and MSLB events inside the containment. It concludes that the containment pressure and temperature remain below their respective design limits.

2.6.5.2.2 QSS and RSS Pump NPSH

The QSS pumps only take suction from the RWST. The QSS pump flow is unaffected by the SPU The SPU has no impact on the NPSH for the QSS pumps.

As a result of GSI-191, a revised RSS pump NPSH calculation has been performed to take into account the installation of a new sump strainer and the increase in postulated debris generation and associated head loss. This calculation also takes into account the NRC approved design change that changes RSS initiation based upon a timer to RSS initiation when the low-low water level setpoint in the RWST is reached. This calculation was previously supplied to the NRC in Reference 2. The current approach is to make all available NPSH and inlet flashing margin available for addressing the increased debris loading.

The parameters used in the revised RSS pump NPSH calculation and the SPU impact is shown in Table 2.6.5-1. As seen by this table the SPU parameters are either unchanged or bounded by the current calculation assumptions. Thus, the SPU has no impact on the RSS NPSH and inlet flashing analysis performed to resolve GSI-191.

2.6.5.2.3 Containment Sump pH

DNC has analyzed the impact of the SPU conditions on the containment sump pH. The ultimate containment sump pH at 30 days post-LOCA was determined to be 7.05. In addition, the containment sump pH was determined to be above 7.0 during the period that the RSS was assumed to operate.

The ultimate containment sump pH was determined using the same calculational method as used to provide the pre-SPU results previously transmitted in Reference 2:

1. Table 2.6.5-2 provides a comparison of the initial conditions and assumptions used for the SPU calculation and the previous transmittal given in Reference 1. Some minor changes in initial conditions and parameters have been made to reflect changes made since the submittal of Reference 2, additional margin for the SPU and re-validation of the parameters.

2. Inside containment there is a minimum of 974 ft^3 of TSP stored in 12 baskets located on the containment floor. The TSP is medium density (54 lbm/ft^3).

3. The titration curves used to determine pH as a function of boron concentration include an allowance for equipment accuracy of 0.03.

4. The sequence of events used to determine the time dependent pH curve is given in Table 2.6.5-3

Figure 2.6.5-1 shows the calculated sump pH as a function of time. It shows that the sump pH increases to 7.0 at approximately 15 minutes and remains above 7.0 for the duration of the transient.

These results have been factored into the calculation of spray effectiveness for the radiological calculations discussed in Section 2.9.2 and the Electrical Equipment Environmental Qualification discussed in Section 2.3.1.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

There are no modification or additions to system components as the result of the SPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the QSS and RSS at SPU conditions does not add any new types of materials or previously unevaluated materials to the system. System components internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.6.5.2.4 Results

DNC has established that the QSS, RSS, and service water system will be able to perform their containment heat removal functions under SPU Conditions.

- Section 2.6.1 provides the containment response analysis that demonstrates the containment pressure and temperature will remain below their respective design limits following a LOCA.
- The QSS and RSS pumps will continue to be provided with adequate NPSH.

In addition, DNC has determined that the ultimate containment sump pH at 30 days post-LOCA will remain above 7.0, and the containment sump pH will be above 7.0 during the period that the RSS is assumed to operate.

2.6.5.3 Conclusion

DNC concludes that the effects of the proposed SPU on the containment heat removal systems are adequately addressed. DNC finds that the systems will continue to meet the requirements of GDC-38 for rapidly reducing the containment pressure and temperature following a LOCA, and for maintaining them at acceptably low levels. Therefore, DNC finds the proposed SPU acceptable with respect to containment heat removal systems.

2.6.5.4 References

1. DNC letter to the NRC, “Millstone Power Station Unit 3, Proposed Technical Specifications Change, Recirculation Spray System,” dated September 13, 2005.

2. DNC letter to the NRC, “Millstone Power Station Unit 3, Supplement to Proposed Technical Specification Change, Recirculation Spray System,” dated June 13, 2006.

3. DNC letter to the NRC, “Millstone Power Station Unit 3 Implementation Period for Proposed Technical Specification Changes, Recirculation Spray System,” dated August 14, 2006.

4. NRC letter to DNC, “Millstone Power Station Unit No. 3, Issuance of Amendment Re: Recirculation Spray System (TAC NO. MC8327),” dated September 20, 2006.

5. Regulatory Guide 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors.”

Table 2.6.5-1
RSS NPSH Parameters

Parameter	Current Value	SPU value	Impact
Minimum Sump Elevation above E. (-)24’6”, feet	4.33	4.33	Unchanged
Maximum RSS flow, gpm	8220	8220	Unchanged
Maximum Sump Temperature, °F	260	225	Bounded by current calculation
Credit for containment back pressure	NO	NO	Unchanged

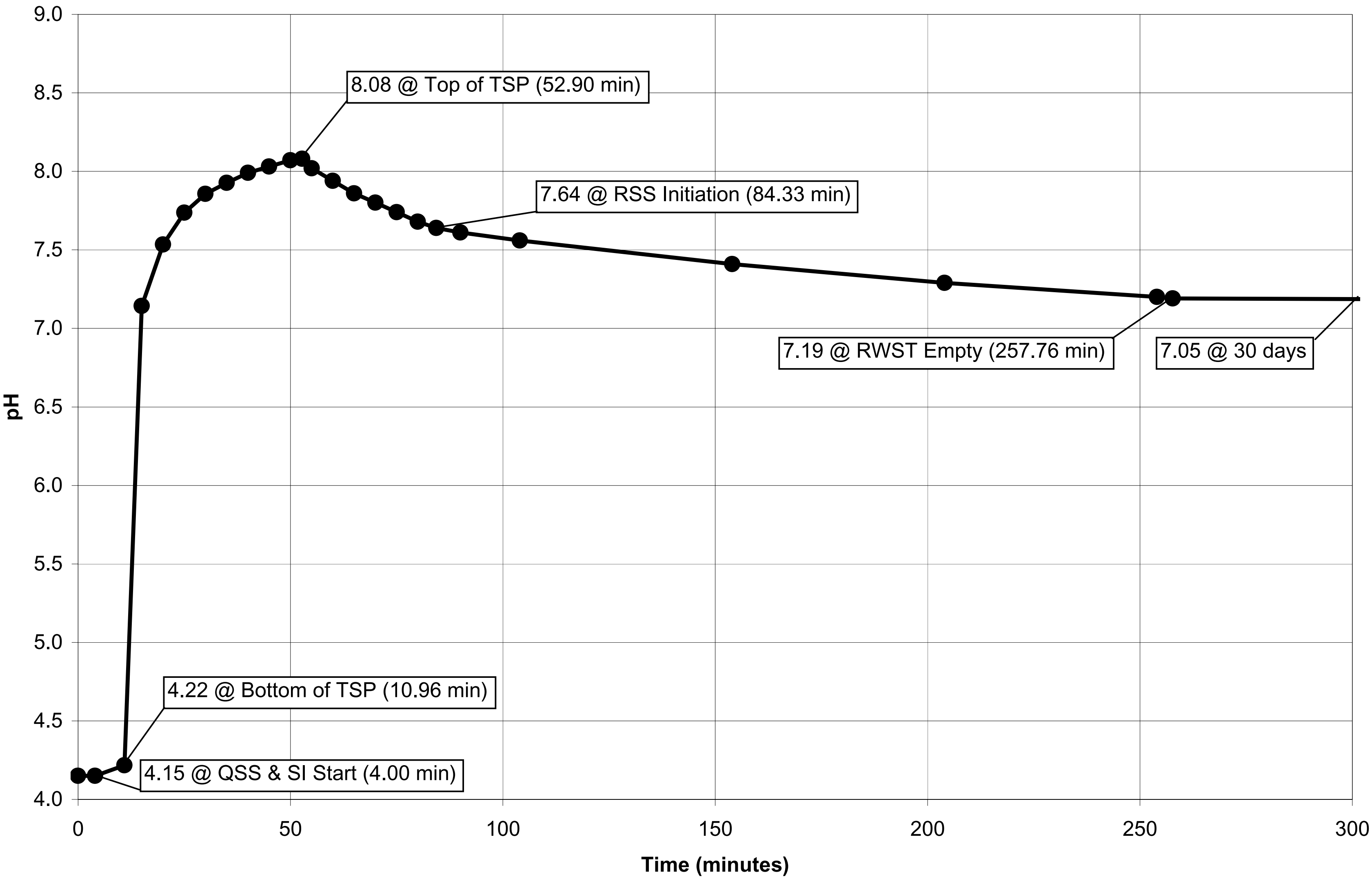
Table 2.6.5-2
Comparison of SPU Parameters and Parameters Used in Sump pH Calculation

Parameter	Input used in Sump pH Calculation provided in Reference 2	Input used in SPU analysis	Discussion
Post LOCA atmosphere beta and gamma dose, megarads	200	220	Increased to account for the increase in source term for SPU
Post LOCA sump water beta and gamma dose, megarads	40	43	Increased to account for the increase in source term for SPU
Time for RSS initiation, seconds	780	5060	Revised to reflect NRC approved change of RSS start from 11 minute timer to actuation at low-low RWST water level setpoint
RCS Volume (excluding the pressurizer and surge line), gallons	78,000	77,000	Reference 2 used a pre-construction value. The SPU has been updated based upon as built drawings
Maximum Pressurizer and Surge Line mass, lbm	46,000	66,000	Reference 2 used a pre-construction value. The SPU has been updated based upon as built drawings
RWST volume, million gallons	1.16	1.16	Unchanged
Maximum RWST boron concentration, ppm	2900	2900	Unchanged
Boron concentration measurement uncertainty, %	0	1	Impact of measurement uncertainty is negligible
Maximum volume of four accumulators, gallons	28,000	28,000	Unchanged
Maximum accumulator boron concentration, ppm	2900	6000	Increased for conservatism

Table 2.6.5-3 Sequence of Events for Determining Containment Sump pH

Event	Time, minutes
Break initiation, RCS added to sump	0
Quench spray initiated	0.83 (50 seconds)
Quench spray flow reaches sump	4
Sump level reaches TSP baskets	11
TSP baskets fully submerged	53
RSS Initiation Time	84 (5060 seconds)
Cold leg recirculation initiated	258
End of transient	30 days

Figure 2.6.5-1
Post-LOCA Sump pH as a Function of Time



2.6.6 Pressure Analysis for ECCS Performance Capability

2.6.6.1 Regulatory Evaluation

Following a LOCA, the ECCS will supply water to the RV to reflood, and thereby cool the reactor core. The core flooding rate will increase with increasing containment pressure. The DNC review covered analyses of the minimum containment pressure that could exist during the period of time until the core is reflooded to confirm the validity of the containment pressure used in ECCS performance capability studies. The DNC review covered assumptions made regarding heat removal systems, structural heat sinks, and other heat removal processes that have the potential to reduce the pressure.

The acceptance criterion for the pressure analysis for ECCS performance capability is based on

- 10 CFR 50.46, insofar as it requires the use of an acceptable ECCS evaluation model that realistically describes the behavior of the reactor during LOCAs or an ECCS evaluation model developed in conformance with 10 CFR 50 Appendix K.

Specific review criteria are contained in SRP Section 6.2.1.5, and guidance provided in Matrix 6 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800), SRP Section 6.2.1.5, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

FSAR Section 6.2.1.5 describes the containment backpressure analysis used in the large break LOCA analysis. The containment backpressure used for the limiting case break for the ECCS analysis (See FSAR Section 15.6.5.2) is depicted on FSAR Figure 6.2-59. The containment backpressure is calculated using the methods and assumptions described in Appendix A of WCAP-8339 (1974). FSAR Section 6.2.1.5 describes the input parameters including the containment initial conditions, net containment volume, passive heat sink materials, thicknesses, surface areas, and starting time and performance parameters for containment cooling systems used in the analysis. The mathematical models which calculate the mass and energy releases to the containment are described in FSAR Section 15.6.5.2 and conform to 10 CFR 50, Appendix K, ECCS Evaluation Models.

NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, defines the scope of license renewal. The evaluation of pressure analysis for ECCS performance capability is not within the scope of license renewal.

2.6.6.2 Technical Evaluation

This section discusses the containment backpressure analysis used in the large break LOCA analysis to support the MPS3 SPU.

Introduction

The system hydraulic transient for a large break LOCA is influenced by the containment pressure transient response to the mass and energy released from the reactor coolant system by the LOCA. In the best estimate ECCS evaluation model using the automated statistical treatment of uncertainty method (ASTRUM) (Reference 2), the containment pressure transient is provided as a boundary condition to the system hydraulic transient. The containment pressure transient applied is to be conservatively low and include the effect of the operation of all pressure-reducing systems and processes. The COCO computer code (Reference 1) is used to generate the containment pressure response to the mass and energy release from the break from a reference WCOBRA/TRAC transient. This containment pressure curve is then used to determine an appropriate input to the WCOBRA/TRAC code as sanctioned by the large break LOCA evaluation model (Reference 2).

Input Parameters, Assumptions, and Acceptance Criteria

Table 2.6.6-1 provides the general parameters used in the ECCS containment backpressure boundary condition analysis. Table 2.6.6-2 provides the structural heat sink data used in the ECCS containment backpressure boundary condition analysis. The structural heat sink data has been updated to reflect re-validation of the data and implemented design changes, including the sump strainer. Also, certain input parameters have been changed from the prior analysis due to the stretch power uprate. See Table 2.6.6-1 for parameters that have changed for the SPU analysis.

As specified in 10 CFR 50, Appendix K: “The containment backpressure boundary condition analysis is acceptable if the containment pressure used for evaluating the cooling effectiveness during reflood does not exceed a pressure calculated conservatively for this purpose. The calculation should include the effects of operation of all installed pressure reducing systems and processes.”

Description of Analyses and Evaluations

The containment backpressure analysis for a large break LOCA was performed for the SPU using the COCO computer code (Reference 1) as sanctioned by the large break LOCA evaluation model (Reference 2). The application of this code is consistent with Westinghouse Emergency Core Cooling System Evaluation Model Summary, WCAP-8339 Appendix A (Non-Proprietary), June 1974 (Reference 3). This analysis reflects the MPS3 specific parameters as discussed in Section 2.6.3.2.2. The result of this analysis is discussed in Section 2.6.3.2.3.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the Pressure Analysis for ECCS Performance Capability. As stated in Section 2.6.6.1, transient analyses are not within the scope of license renewal.

Therefore, there is no impact on the evaluations performed for license renewal and they remain valid for the SPU conditions.

2.6.6.2.1 Results

Figure 2.6.6-1 provides a plot of the containment pressure curve used as an input into the WCOBRA/TRAC computer code and the containment pressure curve calculated by the COCO computer code. This curve is based on the parameters for the SPU analysis. The containment pressure curve used as an input to the WCOBRA/TRAC code for the thermal-hydraulic calculations is at a lower pressure than the containment pressure curve calculated by the COCO computer code. As such, the containment pressure curve used in the large break LOCA analysis is acceptable to be used in the large break LOCA analysis since it fulfils 10 CFR 50.46 criteria.

Since the RCS has more energy at uprated power conditions when compared to the non-uprated power conditions, the energy release associated with a large break LOCA at uprated conditions increases. Therefore, the minimum containment pressure response for a large break LOCA at uprated power conditions is greater than that of the non-uprated conditions.

2.6.6.3 Conclusion

DNC has reviewed the assessment of the impact that the proposed SPU would have on the minimum containment pressure analysis and concludes that the assessment has adequately addressed this area of review to ensure that the requirements in 10 CFR 50.46 regarding ECCS performance will continue to be met following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to minimum containment pressure for ECCS performance.

2.6.6.4 References

1. F. M. Bordelon and E. T. Murphy, Containment Pressure Analysis Code (COCO), WCAP-8327 (Proprietary Version), WCAP-8326 (Non-Proprietary Version), June 1974.

2. M. E. Nissley et. al., Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM), WCAP-16009-P-A (Proprietary Version), WCAP-16009-NP-A (Non-Proprietary Version), January 2004.

3. F. M. Bordelon et. al., Westinghouse Emergency Core Cooling System Evaluation Model Summary, WCAP-8339 Appendix A (Non-Proprietary), June 1974.

Table 2.6.6-1
Parameters for ECCS Containment Backpressure Analysis

Containment Net Free Volume	2,350,000 ft^3
Initial Conditions	
Minimum air initial containment partial pressure at full power operation	8.9 psia(1)
Minimum steam initial containment partial pressure at full power operation	0.00 psia
Minimum initial containment temperature at full power operation	80°F(2)
RWST temperature	40.0°F
Temperature outside containment	-20°F
Initial spray temperature	40.0°F
Quench Spray System	
Number of containment spray pumps operating	2
Post-accident containment spray system initiation delay	26.3 sec(3)
Maximum spray system flow from all containment spray pumps	6500 gal/min.
Fan Coolers	Not modeled(4)
Recirculation Spray	Not modeled(5)

Notes:
1. This parameter was changed from 10.4 psia to 8.9 psia for the SPU analysis.
2. This parameter was changed from 90°F to 80°F for the SPU analysis.
3. Assumes offsite power is available
4. The containment atmosphere recirculation fans A and B are stopped automatically on receipt of a CDA signal, even if the SIS or LOP signal has previously started the fans. Component cooling water is provided to the containment air recirculation cooling coils instead of chilled water on receipt of an LOP or CIA signal.
5. The time at which the recirculation spray pumps are actuated is based on the low RWST level signal. The fastest time to low-RWST level signal is 1962 seconds, which is past the PCT-time calculated for the Best Estimate Large Break LOCA. Therefore, containment recirculation spray is not modeled in the Best Estimate Large Break LOCA.

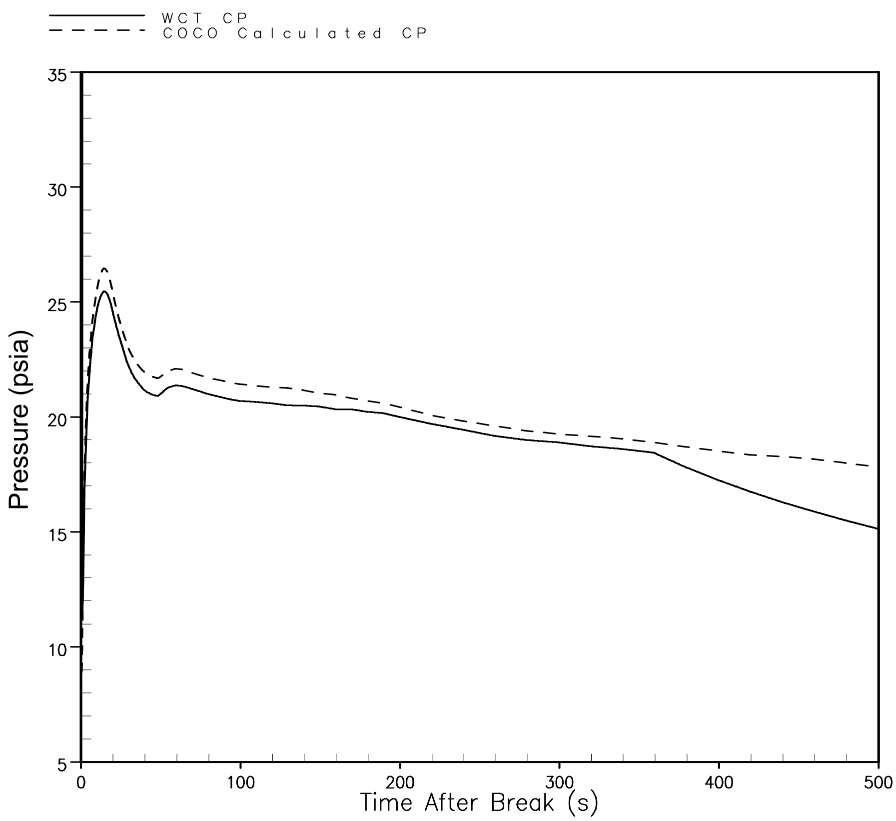
Table 2.6.6-2 Structural Heat Sink Data for ECCS Containment Backpressure Analysis

Structural Heat Sinks					
	Wall (feet)	T_{Air} (°F)	Area (ft^2)	Height (ft)	$T_{initial}$ (°F)
1.	0.0375 stainless steel, 2.16 concrete	80	866	10.0	80
2.	0.375 stainless steel, 1.50 concrete	80	7,674	10.0	80
3.	1.36 concrete	80	133,277	10.0	80
4.	2.11 concrete	80	17,926	10.0	80
5.	3.00 concrete	80	6,563	10.0	80
6.	1.75 concrete	80	2,007	10.0	80
7.	2.00 concrete, 0.25 carbon steel, 10.00 concrete	55	12,269	10.0	80
8.	0.0428 carbon steel, 4.5 concrete	55	24,675	10.0	80
9.	0.0428 carbon steel, 4.5 concrete	-20	38,493	10.0	80
10.	0.0462 carbon steel, 2.56 concrete	-20	34,100	10.0	80
11.	0.1075 stainless steel	80	1,722	10.0	80
12.	0.0592 carbon steel	80	552	10.0	80
13.	0.02 stainless steel	80	13,230	10.0	80
14.	0.0548 stainless steel	80	2,063	10.0	80
15.	0.0231 carbon steel	80	8,966	10.0	80
16.	0.0825 carbon steel	80	1,282	10.0	80
17.	0.0182 carbon steel	80	514,279	10.0	80
18.	0.00925 carbon steel	80	182,517	10.0	80
19.	0.0304 stainless steel	80	11,033	10.0	80
20.	0.0651 carbon steel	80	37,068	10.0	80
21.	0.0119 steel	80	21,000	10.0	80

Table 2.6.6-2 Structural Heat Sink Data for ECCS Containment Backpressure Analysis

Structural Heat Sinks					
	Wall (feet)	**T_{Air} (°F)**	**Area (ft^2)**	**Height (ft)**	**$T_{initial}$ (°F)**
22.	2.16 concrete	80	866	10.0	80
23.	1.50 concrete	80	7,674	10.0	80

Figure 2.6.6-1 COCO Calculated Containment Backpressure (using mass and energy release from a reference WCOBRA/TRAC transient) and WCOBRA/TRAC Input Containment Backpressure Versus Time After Break



2.7 Habitability, Ventilation, and Filtration

2.7.1 Control Room Habitability System

2.7.1.1 Regulatory Evaluation

DNC reviewed the control room habitability system and Control Building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. DNC's review focused on the effects of the proposed SPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination.

The acceptance criteria for the control room habitability system are based on

1. GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with postulated accidents, including the effects of the release of toxic gases; and

2. GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident.

Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, SRP 6.4, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to

- GDC-4, Environmental and Missile Design Bases, is described in FSAR Section 3.1.2.4.

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents, including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-19, Control Room, is described in FSAR Section 3.1.2.19.

  The control room provided is equipped to operate the unit safely under normal and accident conditions. Its shielding and ventilation design permits continuous occupancy of the control room for the duration of a DBA without the dose to personnel exceeding 5 rem whole body. Based on 10 CFR 50.67, the applicable dose criterion was modified to 5 rem TEDE.

  The auxiliary shutdown panel located in the west switchgear room has equipment, controls, and instrumentation to accomplish, in conjunction with controls and indication located on the adjacent 4160V emergency switchgear, a prompt hot shutdown and a safety grade cold shutdown. The panel is physically located outside the control room. Thus, the uninhabitability of the control room would have no effect on the availability of the auxiliary shutdown panel and adjacent controls (FSAR Section 7.4.1.3).

  FSAR Section 3.8.4 describes the design of the Control Building, which houses the control room and the auxiliary shutdown panel area. FSAR Section 9.4.1 describes the Control Building ventilation system. Control room habitability is discussed in FSAR Section 6.4.1. Fire protection systems are discussed in FSAR Section 9.5.1.

FSAR Section 6.4 states that the habitability systems for the control room envelope include radiation shielding, redundant air supply and filtration systems, redundant air-conditioning systems, fire protection, personnel protective equipment, first aid, food, water storage, emergency lighting, and sanitary facilities.

As stated in FSAR Section 6.4.2, the control room envelope contains the control room area, shift supervisor's office, day shift supervisor's office, viewing gallery and ramp, training room, operations supervisor's office, toilet, kitchenette, instrument rack and computer room, piping/duct chase, and the mechanical room. Within The control room envelope, all essential equipment necessary to operate the nuclear power plant and maintain a habitable environment during a postulated DBA is provided.

The control room air-conditioning subsystem consists of two redundant 100 percent capacity air-conditioning units, each containing a fan, cooling coil, an electric heating element, and filter. The air distribution ductwork within each area is common to both trains. FSAR Section 9.4.1 gives the design bases and description of the Control Building HVAC system.

The control room emergency ventilation filtration and pressurization system consists of redundant air storage tanks and two redundant emergency air filtration units. As stated in FSAR Section 6.4.2.2, each control room emergency ventilating filtration assembly consists of a moisture separator, electric heater, prefilter, upstream high efficiency particulate air (HEPA) filter, charcoal adsorber, and downstream HEPA filter.

Following a DBA, breathable air is supplied from the air storage banks to the control room pressure envelope. The radiological accident analyses do not credit the air storage banks for pressurization. An emergency ventilating subsystem is started upon depletion of the air storage banks (FSAR Section 9.4.1). This subsystem introduces filtered, breathable air into the control room.

Technical Specification 3/4.7.7 provides the requirements that ensure the operability of the control room emergency ventilation system.

Section 2.9.2 provides a detailed discussion of the current licensing basis for the analyses that establish the radiological consequences to the operators in the control room for various events. Following an accident, the control room inlet radiation monitor generates a Control Building isolation (CBI) signal. Following a short time delay, the control room isolates upon receipt of the CBI signal. The control room envelope pressurization system discharges to the control room following a time delay. However, no credit is taken for the capability of this system to pressurize the control room. During the time period that the control room envelope pressurization system is discharging, the control room is assumed to be at a neutral pressure. After one hour, the control room emergency ventilation system will be placed in service in the filtered pressurization mode. FSAR Table 15.6-12 provides the assumptions utilized in the analyses regarding control room habitability.

As stated in FSAR Section 6.4.4.2, there are no analyzed chemical spills that could affect control room habitability. The effects of spills of chemicals along transportation routes are evaluated in FSAR Section 2.2.3.2. At the discretion of the operator, the control room can be isolated in the case of chemical spills in the vicinity of the plant. As shown in FSAR Section 2.2, no offsite storage or transport of chlorine is close enough or frequent enough to be considered a hazard. There is no onsite chlorine that is considered a hazard under RG 1.78. A sodium hypochlorite biocide system is used, thus eliminating an onsite chlorine hazard. Therefore, special provisions for protection against chlorine gas are not provided in the control room habitability design.

Section 2.7.1 of RS-001 identifies that one of the objectives of the review was to ensure that the control room can serve as a backup location to permit Technical Support Center personnel to perform their duties in a safe environment. At MPS3, the control room does not serve as the backup Technical Support Center.

The Technical Support Center is located adjacent to the west side of the MPS3 Control Building. The alternate Technical Support Center is located in the Emergency Operations Facility, which is located approximately one mile north of the station’s protected area on the west side of the access road (MPS3 Emergency Plan).

The MPS3 control room habitability system and control room were evaluated for the continued acceptability for the purpose of plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. The control room habitability system is addressed in Sections 2.3B.3.25 and 3.3B.2.3.24, and the control room is discussed in Sections 2.4B.2.3 and 3.5B.2.3.4 of NUREG-1838.

2.7.1.2 Technical Evaluation

Section 2.9.2 establishes the impact of the SPU conditions on the post-accident radiological consequences. It includes changes to the assumptions regarding the control room emergency ventilation system. The following are the changes directly associated with control room habitability:

1. The control room emergency ventilation system's filter efficiencies are changed to 95 percent for elemental, aerosol, and organic iodines. This change is consistent with the requirements of Technical Specification 3/4.7.7.

2. In the case of a fuel handling accident involving the drop of a spent fuel assembly, the control room emergency ventilation system is now required to be in the pressurized filtration mode of operation within 30 minutes. A modification will be implemented to support this change.

3. In the analyses of the radiological consequences of a LOCA and RCCA ejection accident, operator action is no longer credited to trip breakers for the ESF Building, Auxiliary Building, and MSV Building normal exhaust fans.

Section 2.9.2 concludes that the radiological consequences to the operators in the control room remain within the limits specified in GDC-19, 10 CFR 50.67, and RG 1.183.

As stated in FSAR Section 6.4.4.2, there are no analyzed chemical spills that could affect control room habitability.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

A modification will be implemented that will require the control room emergency ventilation system to be initiated utilizing a different method. This change will not introduce any new aging concerns.

There are no modifications or additions to system components as the result of the SPU that would introduce any new functions or change the functions of existing components that would affect the license renewal evaluation boundaries. Operation of the control room habitability system at SPU conditions does not add any new types of materials or previously unevaluated materials to the system. System components internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.7.1.3 Results

Section 2.9.2 establishes the impact of the SPU conditions on the post-accident radiological consequences. The control room, EAB, and LPZ doses remain within the limits specified in GDC-19, 10 CFR 50.67, and RG 1.83.

2.7.1.4 Conclusion

DNC has reviewed the effects of the proposed SPU on the ability of the control room habitability system to protect plant operators against the effects of accidental releases of toxic and radioactive gases. DNC concludes the analyses have adequately accounted for the increase of radioactive gases that would result from the proposed SPU. DNC concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed SPU. Based on this, DNC concludes that the control room habitability system will continue to meet the requirements of GDC-4 and -19. Therefore, DNC finds the proposed SPU acceptable with respect to the control room habitability system.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

2.7.2.1 Regulatory Evaluation

ESF atmosphere cleanup systems are designed for fission product removal in post-accident environments. For MPS3, these systems are the control room emergency ventilation system, the charging pump, component cooling water pump and heat exchanger exhaust ventilation system, SLCRS, QSS, and RSS. For each ESF atmosphere cleanup system, DNC's review focused on the effects of the proposed SPU on system functional design and environmental design.

The acceptance criteria for the ESF atmosphere cleanup systems are based on

- GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident.
- GDC-41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents.
- GDC-61, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions.
- GDC-64, insofar as it requires that means shall be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences (AOOs), and postulated accidents.

Specific review criteria are contained in SRP Section 6.5.1 and other guidance provided in Matrix 7 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, SRP 6.5.1, Rev. 2.

As noted in the FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to

- GDC-19, Control Room, is described in FSAR Section 3.1.2.19.

  The control room provided is equipped to operate the unit safely under normal and accident conditions. Its shielding and ventilation design permits continuous occupancy of the control room for the duration of a DBA without the dose to personnel exceeding 5 rem whole body. Based on 10 CFR 50.67, the applicable dose criterion is 5 rem TEDE.

  The auxiliary shutdown panel located in the west switchgear room has equipment, controls, and instrumentation to accomplish, in conjunction with controls and indication located on the adjacent 4160V emergency switchgear, a prompt hot shutdown and a safety grade cold shutdown. The panel is physically located outside the control room. Thus, the uninhabitability of the control room would have no effect on the availability of the auxiliary shutdown panel and adjacent controls (FSAR Section 7.4.1.3).

The design of the Control Building (FSAR Section 3.8.4), which houses the control room and the auxiliary shutdown panel area, conforms to Criterion 19. FSAR Section 9.4.1 describes the Control Building ventilation system. Control room habitability is discussed in FSAR Section 6.4.1. Fire protection systems are discussed in FSAR Section 9.5.1.

- GDC-41, Containment Atmosphere Cleanup, is described in FSAR Section 3.1.2.41:

  The SLCRS collects radioactive leakage from the Containment to the containment enclosure and contiguous areas following a LOCA (FSAR Section 6.2.3.2).

  The QSS sprays borated water into the containment atmosphere to reduce the containment pressure. The pH in the containment sumps is controlled by the dissolution of trisodium phosphate (stored in baskets) in the sump water (FSAR Section 6.2.2).

  These systems are sufficiently redundant to perform their safety function assuming a single active failure in the short term or a single active or passive failure in the long term and are operable with either onsite or offsite power.

- GDC-61, Fuel Storage and Handling and Radioactive Control, is described in FSAR Section 3.1.2.61.

  The new and spent fuel storage areas are designed to meet the requirements of 10 CFR 20 in providing radiation shielding for operating personnel during new and spent fuel transfer and storage. The fuel transfer canal and spent fuel pool wall thickness are sufficient to shield adjacent work areas to meet the requirements of 10 CFR 20 for personnel access during actual fuel transfer. Waste storage and processing facilities in the Auxiliary Building and the Waste Disposal Building are shielded to meet the requirements of 10 CFR 20 for operating personnel. Periodic surveys by radiation protection personnel and continuously operated radiation monitors located in areas selected to afford maximum personnel protection (FSAR Section 12.1) ensure that radiation design levels are not exceeded during the operating lifetime of the unit.

  New and spent fuel handling systems are designed to preclude gross mechanical failures that could lead to significant radioactivity releases. Floor and equipment drains are provided to collect leakage that might occur from valve stem leakoffs, pump seals, and other equipment, and to transfer the leakage to one of the building sumps for eventual processing by the liquid waste system.

  Radiation gases and particulates released from components are collected by the reactor plant aerated vents system. Uncontrolled leakage of radioactive gases and particulates that may leak from spent fuel, radioactive waste, or components containing radioactive fluids is collected and treated by the respective building ventilation filtration system (FSAR Section 9.4) or supplementary leakage collection and release system (FSAR Section 6.5.1). All discharges from these systems are monitored for radioactivity.

- GDC-64, Monitoring Radioactivity Releases, is described in FSAR Section 3.1.2.64.

  The containment atmosphere is monitored during normal and transient operations of the reactor plant by the Containment structure particulate and gas monitor located in the upper level of the auxiliary building (FSAR Section 12.3.4) or by grab sampling. Normal unit effluent discharge paths are monitored during normal plant operation by the ventilation particulate samples and gas monitors in the Auxiliary and Engineered Safety Buildings (FSAR Section 11.5). After a postulated accident, the safety-related ventilation vent monitors and the safety-related SLCRS monitors are used to monitor the effluents from spaces contiguous to the Containment structure, including the areas that contain loss-of-coolant accident fluids. In addition, the service water outlet from each pair of containment recirculation coolers is monitored to ensure that any leakage of radioactive fluids into the service water system is detected (FSAR Section 11.5). Radioactivity levels in the environs are controlled during normal and accident conditions by the various radiation monitoring systems (FSAR Sections 11.5 and 12.3.4) and monitored by the collection of samples as part of the offsite radiological monitoring program.

QSS and RSS are credited with the removal of fission products from the containment atmosphere following a LOCA. The QSS and RSS systems are described in FSAR Sections 6.5.2 and 6.2.2.

FSAR Section 6.5.1 identifies the following ventilation filter systems as ESF filter systems:

1. Control room emergency ventilation system. This system is described in FSAR Section 9.4.1.

2. Charging pump, component cooling water pump, and heat exchanger exhaust ventilation system. This system is part of the Auxiliary Building ventilation system and is described in FSAR Section 9.4.3; and

3. SLCRS. This system is described in FSAR Section 6.2.3.

The control room, control room habitability system, QSS, RSS, SLCRS, and Auxiliary Building ventilation system were evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. The control room habitability system is addressed in NUREG-1838 Sections 2.3B.3.25 and 3.3B.2.3.24, and the control room is discussed in NUREG-1838 Sections 2.4B.2.3 and 3.5B.2.3.4. The QSS is addressed in NUREG-1838 Sections 2.3B.2.2 and 3.2B.2.3.2. The RSS is addressed in NUREG-1838 Sections 2.3B.2.1 and 3.2B.2.3.1. The SLCRS is addressed in NUREG-1838 Sections 2.3B.3.35 and 3.2B.2.3.33. The Auxiliary Building ventilation system is addressed in NUREG-1838 Sections 2.3B.3.18 and 3.3B.

2.7.2.2 Technical Evaluation

2.7.2.2.1 Control Room

Section 2.7.1 provides additional discussion regarding the impacts of the SPU on the SSCs that are credited for ensuring control room habitability. Section 2.9.2 establishes the impact of the SPU conditions on the post-accident radiological consequences, including any changes to the analysis regarding radiological consequences for the control room. The analyses conclude that the radiological consequences to the operators in the control room remain within the limits specified in GDC-19, 10 CFR 50.67, and RG 1.183. Therefore, the SSCs that are credited for ensuring control room habitability remain effective in limiting dose within the control room.

2.7.2.2.2 Containment

The QSS and RSS are credited for the removal of fission products from the containment atmosphere following a LOCA. The SLCRS is credited for the removal of fission products from the atmosphere of the secondary containment (FSAR Section 6.5.3.2) during design basis accidents. Section 2.5.3.1 describes the impact of the SPU on the specific systems.

Section 2.9.2 discusses the impacts of the SPU on the analyses of the radiological consequences following a design basis accident, including any changes to the assumptions regarding QSS, RSS, and SLCRS operation. The analyses conclude that the off-site and control room doses due to the design basis accidents remain within the applicable regulatory criteria. Therefore, the QSS, RSS, and SLCRS, in conjunction with other SSCs, remain effective in limiting the doses to the control room and off-site individuals.

2.7.2.2.3 Auxiliary Building Ventilation System

Section 2.7.5 provides additional discussion regarding the impacts of the SPU on the Auxiliary Building ventilation system, including the charging pump, component cooling water pump, and heat exchanger exhaust ventilation system.

Section 2.9.2 discusses the impacts of the SPU on the analyses of the radiological consequences following design basis accidents, including any changes to the assumptions regarding operation of the charging pump, component cooling water pump, and heat exchanger exhaust ventilation system. The analyses conclude that the off-site and control room doses due to the design basis accidents remain within the applicable regulatory criteria. Therefore, the charging pump, component cooling water pump, and heat exchanger exhaust ventilation system, in conjunction with other SSCs, remain effective in limiting the doses to the control room and off-site individuals.

2.7.2.2.4 Spent Fuel Pool Area Ventilation

Section 2.7.4 provides additional discussion regarding the impacts of the SPU on the spent fuel pool area ventilation system. The spent fuel pool area ventilation system is not defined as an ESF filter system in FSAR Section 6.5.1.

Section 2.9.2 discusses the radiological consequence analysis for the fuel handling accident. The analysis assumes an unfiltered release, and does not take any credit for the spent fuel pool area ventilation system. The analysis concludes that the off-site and control room doses due to the fuel handling accident remain within the applicable regulatory criteria.

Renewed Plant Operating License Evaluations and License Renewal Programs

There are no modifications or additions to system components as the result of the SPU that would introduce any new functions or change the functions of existing components that would affect the license renewal evaluation boundaries. Operation of the control room control room habitability system, QSS, RSS, SLCRS, and the Auxiliary Building ventilation system at SPU conditions does not add any new types of materials or previously unevaluated materials to the system. System components internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.7.2.2.5 Results

Section 2.9.2 establishes the impact of the SPU conditions on the post-accident radiological consequences. The control room, EAB, and LPZ doses remain within the limits specified in GDC-19, 10 CFR 50.67, and RG 1.183.

2.7.2.3 Conclusion

DNC has reviewed the effects of the proposed SPU on the ESF atmosphere cleanup systems. DNC concludes that it has adequately accounted for the increase of fission products and changes in expected environmental conditions that would result from the proposed SPU. DNC further concludes that the ESF atmosphere cleanup systems will continue to provide adequate fission product removal in post-accident environments following implementation of the proposed SPU. Based on this, DNC concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of GDC-19, -41, -61, and -64. Therefore, DNC finds the proposed SPU acceptable with respect to the ESF atmosphere cleanup systems.

2.7.3 Ventilation Systems

2.7.3.1 Control Room Area Ventilation System

2.7.3.1.1 Regulatory Evaluation

The function of the control room area ventilation system (Control building ventilation system) is to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components during normal operation and DBA conditions. The DNC review of the Control building ventilation system focused on the effects that the proposed SPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products, and the expected environmental conditions in areas served by the Control building ventilation system.

The acceptance criteria for the review are

- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.
- GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.
- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

Specific review criteria are contained in SRP Section 9.4.1 and guidance is provided in Matrix 7 of RS-001.

Millstone 3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Sections 9.4.1, Rev. 2. MPS3 took exception to SRP 9.4.1, Rev. 2, Section II.4 – compliance with RG 1.95. The chlorine detectors are not Seismic Category I. Note that chlorine monitors were subsequently removed.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 Station design relative to conformance to

- GDC-4 is described in the FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4).

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents, including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the require operational period.

Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-19 is described in the FSAR Section 3.1.2.19, Control Room (Criterion 19).

  The control room is equipped to operate the unit safely under normal and accident conditions. Its shielding and ventilation design permits continuous occupancy of the control room for the duration of a DBA without the dose to personnel exceeding 5 rem whole body.

  The auxiliary shutdown panel located in the west switchgear room has equipment, controls, and instrumentation to accomplish, in conjunction with controls and indication located on the adjacent 4160V emergency switchgear, a prompt hot shutdown and a safety-grade cold shutdown. The panel is physically located outside the control room. Thus, the loss of Control Room habitability would have no effect on the availability of the auxiliary shutdown panel and adjacent controls (FSAR Section 7.4.1.3).

  The design of the control building (FSAR Section 3.8.4), which houses the control room and the auxiliary shutdown panel area, conforms to Criterion 19. FSAR Section 9.4.1 describes the Control building ventilation system. Control room habitability is discussed in FSAR Section 6.5.1. Fire protection systems are discussed in FSAR Section 9.5.1.

- GDC-60 is described in the FSAR Section 3.1.2.60, Control of Releases of Radioactive Materials to the Environment (Criterion 60).

  In all cases, the design for radioactivity control is based on

  1. The requirements of 10 CFR 20, 10 CFR 50, and 10 CFR 50, Appendix I, for normal operations and for transient situation that might reasonably be anticipated to occur.

  2. 10 CFR 50.67 dose level guidelines for potential accidents of extremely low probability of occurrence.

  All release paths, including ventilation and process streams, are monitored and controlled as described in FSAR Section 11.5.

Additional details that define the licensing basis for the Control building ventilation system are described in FSAR Section 9.4.1, Control Building Ventilation System.

Technical Specification 3/4.7.7, Control Room Emergency Ventilation System, ensures that the control room emergency ventilation system is operable during post-accident operations to ensure both that the temperature of the control room is maintained and that the control room will remain habitable during design bases accidents.

The Control building ventilation system was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.3B.3.25 and 3.3B are applicable to the Control building ventilation system.

2.7.3.1.2 Technical Evaluation

2.7.3.1.2.1 Introduction

The Control building ventilation system consists of the following subsystems:

1. Control Room Air Conditioning Subsystem
2. Control Room Emergency Air Filtration System
3. Instrument Rack and the Computer Room Air Conditioning Subsystem
4. Switchgear Air Conditioning Subsystem
5. Chiller Equipment space Ventilation Subsystem
6. Control Room Toilet and Kitchenette Exhaust Ventilation Subsystem
7. Purge Ventilation Subsystem
8. Battery Room Ventilation Subsystem

During normal operation, the control room ventilation subsystem provides outside air to one of two redundant air conditioning units (ACU) that supply humidified, conditioned air to all control room areas. In the event of high radioactivity levels in the air intake, the control room ventilation system isolates from the outside environment. See Section 2.7.1, Control Room Habitability System, for control room habitability after isolation.

The computer room/instrument rack room ventilation subsystem provides conditioned, recirculation cooling of associated spaces via redundant ACUs. A small amount of outside air from the control room ventilation subsystem is diverted to this subsystem.

The switchgear rooms recirculate air through ACUs for cooling. A small amount of conditioned air is supplied to the inverter rooms for cooling. Outside filtered air provides makeup to the switchgear rooms. Battery room exhaust fans draw air from the switchgear rooms into the battery rooms and then exhaust the air to the outside.

The kitchen exhaust fan is normally in operation exhausting air from the kitchen and toilet areas in the control room.

The Control building purge system is not normally running. When placed in-service, the system draws outside air in through the same ductwork that supplies the control room ACUs and filter units, directs the air to the area selected, and exhausts the air back to the outside environment.

The chilled water system provides chilled water via pumps for cooling the ACUs in the control room, the computer room/instrument rack room, and the switchgear rooms. Service water provides the redundant cooling medium for the ACUs.

2.7.3.1.2.2 Description of Analyses and Evaluations

The Control building ventilation system was evaluated to ensure it is capable of performing its intended functions at SPU conditions. The radiological consequences of a fuel handling accident were evaluated at SPU conditions (Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms). Because of an increase in release in release fractions, it is necessary to credit filtration of control room in-leakage to meet the alternate source term criterion for control room operators. The SPU analysis assumes that the control room emergency ventilation system is placed in the pressurized filtration mode of operation within 30 minutes of the fuel handling accident. This action is required to meet the established dose limits. A modification will be made to automatically start control building pressurized filtration on a CBI signal. Smoke, toxic gas, and external event assumptions and conclusions are also unaffected by the SPU.

Other evaluations are addressed in the following sections:

- Section 2.7.1, Control Room Habitability System, related to control room habitability.
- Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms, related to radiological analysis methods and assumptions.
- Section 2.10.1, Occupational and Public Radiation Doses, related to control of the release of radioactive effluents.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for control building ventilation. As stated in Section 2.7.3.1.1, the control building ventilation system is within the scope of license renewal. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with operation of the control building ventilation system at SPU conditions that impact License Renewal. The SPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.7.3.1.2.3 Results

The Control Room heat gain loads for the ventilation system are not impacted by the SPU. Therefore, the SPU does not affect the maximum Control Room temperatures for an eight-hour SBO event as determined in the current analysis. The control building ventilation system will continue to provide an acceptable control room environment for safe operation of the plant at SPU conditions, following implementation of the modification to automatically start control building pressurized filtration on a CBI signal. Smoke, toxic gas, and external event assumptions and conclusions are unaffected by the SPU. The design criteria, design bases, and safety classification for the control building ventilation system, and the requirements for system performance continue to provide conformance with the requirements of GDC-4, GDC-19, and GDC-60.

2.7.3.1.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the Control building ventilation system. DNC concludes that the evaluation has adequately accounted for both the increase of radioactive gases that would result from a DBA under the conditions of the proposed SPU and associated changes to parameters affecting environmental conditions for control room personnel and equipment. The Control building ventilation system will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed SPU. Based on this, the control room ventilation system will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-4, GDC-19, and GDC-60 following SPU implementation. Therefore, DNC finds the proposed SPU is acceptable with respect to the Control building ventilation system.

2.7.4 Spent Fuel Pool Area Ventilation System

2.7.4.1 Regulatory Evaluation

The function of the spent fuel pool area ventilation system (Fuel building ventilation system) is to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, and control airborne radioactivity in the area during normal operation, anticipated operational transients, and following postulated fuel-handling accidents. The DNC review focused on the effects of the proposed SPU on the functional performance of the safety-related portions of the system.

The acceptance criteria for the review are

- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents.
- GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement and containment.

Specific review criteria are contained in SRP Section 9.4.2 and guidance is provided in Matrix 7 of RS-001.

Millstone 3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Sections 9.4.2, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 Station design relative to conformance to

- GDC-60 is described in the FSAR Section 3.1.2.60, Control of Releases of radioactive Materials to the Environment (Criterion 60).

  In all cases, the design for radioactivity control is based on

  1. The requirements of 10 CFR 20, 10 CFR 50, and 10 CFR 50, Appendix I, for normal operations and for transient situation that might reasonably be anticipated to occur.
  2. 10 CFR 50.67 dose level guidelines for potential accidents of extremely low probability of occurrence.

  All release paths, including ventilation and process streams, are monitored and controlled as described in FSAR Section 11.5.

- GDC-61 is described in the FSAR Section 3.1.2.61, Fuel Storage and Fuel Handling and Radioactive Control (Criterion 61).

Radiation gases and particulates released from components are collected by the reactor plant aerated vents system. Uncontrolled leakage of radioactive gases and particulates which may leak from spent fuel, radioactive waste, or components containing radioactive fluids is collected and treated by the respective building ventilation filtration system (FSAR Section 9.4) or supplementary leakage collection and release system (FSAR Section 6.5.1). All discharges from these systems are monitored for radioactivity.

Additional details that define the licensing basis for the Fuel building ventilation system are described in FSAR Section 9.4.2, Fuel Building Ventilation. FSAR Section 15.7.4, addresses a fuel handling accident.

In addition to the evaluations described above, the Fuel building ventilation system was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005 documents the results of that review. NUREG-1838 Sections 2.3B.3.29 and 3.3B are applicable to the Fuel building ventilation system.

2.7.4.2 Technical Evaluation

2.7.4.2.1 Introduction

The spent fuel pool area ventilation system is part of the Fuel building ventilation system. The Fuel building ventilation system is described in FSAR Section 9.4.2. The Fuel building ventilation system removes heat, maintains personnel comfort, and in the event of high radioactivity levels, sends the building exhaust to the Fuel building ventilation system filters for filtration prior to discharge to the atmosphere. The spent fuel pool ventilation system serves to control airborne radioactivity in the spent fuel pool area during normal operating conditions. This is accomplished by directing air from the Fuel building supply air unit across the spent fuel pool to exhaust air ducts. The flow of air within the Fuel building is directed from areas of low potential for airborne contamination to area of greater potential for airborne contamination.

During normal plant operation, the Fuel building ventilation supply is the waste disposal building ventilation system heating and ventilating units (HVU). Two out of three HVUs take outside air and heat as necessary. The exhaust fan has a greater flow than the supply airflow, which places the building under a slightly negative pressure to preclude potentially contaminated air leaking directly to the environment. The ventilation air is discharged by one non safety-related exhaust fan to the atmosphere via the plant vent on top of the turbine building. A particulate and gas radiation monitor is provided that samples the exhaust air stream prior to the filtration units. On receipt of a high radiation alarm, the exhaust air is manually diverted through one of the safety-related Fuel building filtration units consisting of roughing filters, HEPA filters, and charcoal filters; the normal exhaust fan is stopped, and the associated safety-related fan is started.

During refuel handling or movement of any loads within the spent fuel pool, the exhaust air may be manually diverted through one of the Fuel building filtration units.

2.7.4.2.2 Description of Analyses and Evaluations

The Fuel building ventilation system was evaluated to ensure it is capable of performing its intended functions at SPU conditions. The decay heat loads in the spent fuel pool increase due to the SPU conditions. SPU decay heat loads and pool water temperatures have been evaluated to ensure that the system is capable of performing its intended functions under normal and refueling modes following SPU implementation. Other related evaluations are addressed in the following sections:

- Section 2.5.4.1, Spent Fuel Pool Cooling and Cleanup System
- Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms
- Section 2.10.1, Occupational and Public Radiation Doses

FSAR Section 15.7.4 addresses a fuel-handling accident. The accident has been analyzed using the methods and assumptions contained in RG 1.183. The analysis does not require re-alignment of the Fuel building ventilation system, nor does it require Fuel building integrity.

Impact on Renewed Plant Operating License Evaluations and License Renewal Program

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for the Fuel building ventilation system. As stated in Section 2.7.4.1, the Fuel building ventilation system is within the scope of license renewal. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with operation of the spent fuel pool ventilation system at SPU conditions, and the SPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.7.4.2.3 Results

The temperature in the spent fuel pool area is a function of the heat released from the spent fuel pool. Although the decay heat in the spent fuel increases at SPU conditions, the spent fuel pool water temperature during normal and abnormal conditions does not exceed, due to margin available in the existing analysis, the current analyzed conditions. Refer to Section 2.5.4.1, Spent Fuel Pool Cooling and Cleanup System. Therefore, the spent fuel pool area ventilation system will maintain the required temperature conditions for personnel and equipment during SPU operation.

Since the design of the spent fuel pool area ventilation system will not change following the implementation of the SPU, airborne radioactivity released from the spent fuel in the pool will continue to be collected and exhausted by the Fuel building ventilation system. When required, the exhaust still has the ability to pass through roughing filters, HEPA filters, and charcoal filters prior to release. Therefore, following implementation of the SPU, the control of airborne radioactivity in the spent fuel pool area is not affected.

The evaluation of the ability of the spent fuel pool area ventilation system to maintain the required temperature conditions and to contain radioactivity to permit personnel access during SPU demonstrates that there is no effect on this system design capability by SPU.

2.7.4.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the Fuel building ventilation system. DNC concludes that the evaluation has adequately accounted for the effects of the proposed SPU on the system's capability to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, control airborne radioactivity in the area, control release of gaseous radioactive effluents to the environment, and provide appropriate containment. Based on this, DNC concludes that the spent fuel pool ventilation system will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-60 and -61 and 10 CFR 50, Appendix I, following SPU implementation. Therefore, DNC finds the proposed SPU is acceptable with respect to the spent fuel pool areas ventilation system.

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

2.7.5.1 Regulatory Evaluation

The function of the auxiliary (Auxiliary building ventilation) and radwaste area (Waste Disposal building ventilation) ventilation systems and the turbine area (Turbine building area ventilation) ventilation system is to maintain ambient temperatures in the auxiliary, radwaste equipment areas and Turbine building areas, permit personnel access, and control the concentration of airborne radioactive material in these areas during normal operation, during anticipated operational occurrences, and after postulated accidents. The DNC review focused on the effects of the proposed SPU on the functional performance of the safety-related portions of these systems.

The acceptance criteria for the review are:

- GDC-60 insofar as it requires that the plant design include means to control the release of radioactive effluents

Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4, and guidance is provided in Matrix 7 of RS-001.

Millstone 3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Sections 9.4.3 and 9.4.4, both Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 Station design relative to conformance to

- GDC-60 is described in the FSAR Section 3.1.2.60, Control of Releases of Radioactive Materials to the Environment (Criterion 60).

  In all cases, the design for radioactivity control is based on

  1. The requirements of 10 CFR 20, 10 CFR 50, and 10 CFR 50, Appendix I, for normal operations and for transient situation that might reasonably be anticipated to occur.

  2. 10 CFR 100 dose level guidelines for potential accidents of extremely low probability of occurrence.

     All release paths, including ventilation and process streams, are monitored and controlled as described in FSAR Section 11.5.

Additional details that define the licensing basis for the Auxiliary building ventilation system are described in FSAR Section 9.4.3, Auxiliary Building Ventilation System, the Waste Disposal building ventilation system in FSAR Section 9.4.9, Waste Disposal Building Ventilation System, and the Turbine building area ventilation system in FSAR Section 9.4.4, Turbine Building Area Ventilation System.

Technical Specification 3/4.7.9, Auxiliary Building Filter System, ensures the operability of the Auxiliary building filter system, as well as associated filters and fans. It also ensures that radioactive materials leaking from the equipment within the charging pump, component cooling water pump, and heat exchanger areas following a LOCA are filtered prior to reaching the environment.

Technical Specification 3/4.6.6, Supplementary Leak Collection and Release System, ensures the operability of the supplementary leak collection and release system and ensures that radioactive materials that leak from the primary containment into the secondary containment following a DBA are filtered out and adsorbed prior to release to the environment.

The Auxiliary building ventilation system, Waste Disposal building ventilation system, and Turbine building area ventilation system were evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Units 2 and 3, dated August 1, 2005 documents the results of the review. NUREG-1838 Section Numbers 2.3B.3.18, 2.3B3.38, 2.3B.3.37, and 3.3B are applicable to the Auxiliary building ventilation system, Waste Disposal building ventilation system, and Turbine building area ventilation system.

2.7.5.2 Technical Evaluation

2.7.5.2.1 Introduction

The Auxiliary building ventilation system (FSAR Section 9.4.3) has both a non-safety-related portion and a safety-related portion. The safety-related ventilation system function is to maintain temperatures within specified limits in areas containing safety-related equipment.

The Auxiliary building ventilation non-safety-related heating, ventilation, and air-conditioning subsystem provide clean, filtered, and tempered outdoor air to all levels of the Auxiliary building. The system exhausts air from the equipment rooms and open areas of the Auxiliary building through a closed exhaust system. During normal plant operation, air is exhausted by the filter unit bypass fan to the ventilation vent without filtration. Auxiliary building air is monitored for radioactivity. Highly radioactive exhaust air is manually diverted to one of two 100 percent capacity filter banks of high-efficiency particulate air filters and charcoal filters and to redundant 100 percent capacity fans discharging to the atmosphere via the ventilation vent. This arrangement ensures the proper direction of airflow for removal of airborne radioactivity from the Auxiliary building. To prevent the release of radioactivity directly to the environment, the filter banks start automatically after an accident to assist the SLCRS in maintaining a slightly negative pressure in the Auxiliary building.

The Auxiliary building ventilation system safety-related portion includes the following subsystems:

1. The charging pump cubicles and reactor plant component cooling water pump and heat exchanger area ventilation subsystem is a safety-related ventilation system to remove equipment heat. The system provides supply air from outside and exhausts non-radioactive

air directly to the environment via the plant vent. Exhaust air is monitored for radioactivity. In the event of high radioactivity, the exhaust air is manually aligned to the Auxiliary building filter units. In the filtration mode of operation, air is exhausted through the Auxiliary building filtration units then to the ventilation vent.

2. The SLCRS collects, filters, and releases to the atmosphere the leakages from the Auxiliary building, ESF building, Containment enclosure, and Main Steam Valve building following a DBA. The SLCRS can be put into operation during refueling and other shutdown periods involving work that could release low-level radiation.

3. The MCC and rod control area ventilation system consists of a safety-related recirculating air-conditioning system to remove equipment heat from these areas.

The Waste Disposal building ventilation system (FSAR Section 9.4.9) is non safety-related and, to maintain building temperature, supplies outdoor air throughout the building by three 50 percent capacity heating and ventilating units. The exhaust air is discharged to the ventilation vent during normal operation. Exhaust air is monitored for radioactivity. Highly radioactive exhaust air is diverted to the Auxiliary building filter unit. Two 100 percent exhaust fans draw ventilation air from various areas with the highest radiation contamination potential, thereby inducing airflow from clean areas into potentially contaminated areas and maintaining the potentially contaminated areas at sub-atmospheric pressure.

The Turbine building area ventilation system (FSAR Section 9.4.4) is non safety-related and removes the heat dissipated from equipment, piping, and lighting. The supply portion of the system consists of 4 axial flow fans, each with inlet sound attenuators, mixing plenum, associated ductwork, and intake louvers and dampers. There are also 6 transfer fans, which transfer air from the lower level to the upper level of the Turbine building. The exhaust portion of the system consists of 12 axial flow exhaust fans that draw air from the upper Turbine building elevations and discharge directly to the environment.

2.7.5.2.2 Description of Analyses and Evaluations

The changes in heat loads for the ventilation subsystems in areas served by the Auxiliary building ventilation, Waste Disposal building ventilation, and Turbine building area ventilation systems were evaluated to ensure that the ventilation systems are capable of performing their intended functions under SPU conditions. The evaluation determined the changes to be insignificant and, therefore, would not degrade the safety-related system operation. In addition, since there is only a minor redistribution of air change in the Turbine building ventilation system, there is no impact on the system's capability to provide the appropriate environment for personnel and equipment and to minimize the release of airborne radioactive material to the atmosphere.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for Auxiliary building ventilation, Waste Disposal building ventilation, and Turbine building area ventilation systems. Portions of the Auxiliary building ventilation, Waste Disposal building ventilation, and the Turbine building area ventilation systems are within the scope of license renewal. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Because no modifications are necessary for safety-related ventilation systems components, SPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.7.5.2.3 Results

The Auxiliary building, Waste Disposal building, and Turbine building area temperature does not increase after implementation of the SPU. The insignificant increase in heat load in these buildings is primarily due to the changes in the piping systems operating conditions. The Auxiliary uses outside air exchange to provide cooling. Outside air temperature changes dominate any potential temperature changes caused by SPU.

The evaluation of the plant equipment changes for the proposed SPU did not identify any need to modify the auxiliary (Auxiliary building ventilation) and radwaste area (Waste Disposal building ventilation) ventilation systems and the turbine area (Turbine building area ventilation) ventilation system. There are no equipment changes as a result of SPU that could create a new potentially unmonitored radioactive release path.

2.7.5.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the Auxiliary building ventilation, Waste Disposal building ventilation, and Turbine building ventilation systems. DNC concludes that the evaluation has adequately accounted for the effects of the proposed SPU on the systems' capability to maintain ventilation in the Auxiliary building, Waste Disposal building, and Turbine building and to provide a suitable and controlled environment for safety related components. The safety-related ventilation systems will continue to suitably control the release of gaseous radioactive effluents to the environment following implementation of the proposed SPU. The safety-related ventilation systems will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-60 following SPU implementation. Therefore, DNC finds the proposed SPU is acceptable with respect to the Auxiliary building ventilation, Waste Disposal building ventilation, and the Turbine building area ventilation systems.

2.7.6 Engineered Safety Feature Ventilation

2.7.6.1 Regulatory Evaluation

The function of the ESF building ventilation system is to provide a suitable and controlled environment for ESF components following certain anticipated transients and design basis accidents. The DNC review focused on the effects of the proposed SPU on the functional performance of the safety-related portions of the system. The DNC review covered:

- The ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESF ventilation system performance.
- The capability of the ESF ventilation system to circulate sufficient air to prevent accumulation of flammable or explosive gas or fuel-vapor mixtures from components (e.g., storage batteries and stored fuel).
- The capability of the ESF ventilation system to control airborne particulate material (dust) accumulation.

The acceptance criteria for the review are:

- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.
- GDC-17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of SSCs important to safety.
- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

Specific review criteria are contained in SRP Section 9.4.5 and guidance is provided in Matrix 7 of RS-001.

Millstone 3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Sections 9.4.5, Rev. 2. MPS3 took exception to SRP 9.4.5, Rev. 2

- Section II.4 – the bottoms of the fresh air intakes are not all located at least 20 feet above grade elevation.
- Section II.5 – only normal building vent is monitored.
- Section III.3.b – no protection of ductwork from negative pressure due to tornado.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 Station design relative to conformance to:

- GDC-4 is described in the FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4).

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents, including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

  FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the structures, systems, and components important to safety are designed.

- GDC-17 is described in the FSAR Section 3.1.2.17, Electrical Power Systems (Criterion 17).

  Two connections to the offsite power system are provided. The preferred offsite connection is a backfeed through the main and normal station service transformers with the generator breaker open. The alternate offsite connection is through the reserve station service transformers. Each offsite source has 100 percent capacity for all emergency and normal loads during all phases of operation. Also, as an alternate offsite source for minimum post-accident loads, each source has the capacity to supply Millstone Unit 2 GDC-17 requirements through the normal station service transformer or reserve station service transformer.

  Two onsite power systems are provided. Each system has an emergency diesel generator. Each diesel generator has 100 percent capacity for the emergency loads in the event of the postulated accidents or if required for reactor cooldown.

  The design of the electrical system (FSAR Chapter 8) conforms to Criterion 17.

- GDC-60 is described in the FSAR Section 3.1.2.60, Control of Releases of Radioactive Materials to the Environment (Criterion 60).

In all cases, the design for radioactivity control is based on:

1. The requirements of 10 CFR 20, 10 CFR 50, and 10 CFR 50, Appendix I, for normal operations and for transient situation that might reasonably be anticipated to occur.

2. 10 CFR 50.67 dose level guidelines for potential accidents of extremely low probability of occurrence.

All release paths, including ventilation and process streams, are monitored and controlled as described in FSAR Section 11.5.

Additional details that define the licensing basis for the ESF building ventilation system are described in these FSAR sections:

- Section 9.4.5, Engineered Safety Features Building Ventilation System.
- Section 9.4.6, Emergency Generator Enclosure Ventilation System.
- Section 9.4.8, Circulating and Service Water Pumphouse and Other Structures Ventilation Systems.
- Section 9.4.11, Hydrogen Recombiner Building Heating, Ventilation, and Air-conditioning (HVAC) System.

All of the safety-related ESF building ventilation subsystems are located in a Seismic Category I structure that is tornado, missile, and flood-protected. The redundant components are connected to redundant Class 1E buses and can function as required in the event of loss of offsite power. The safety-related ESF building ventilation system can withstand a single active component failure or failure of one of its Class 1E electric power sources without degrading the performance of safety function (FSAR Section 9.4.5.3).

In addition to the evaluations described above, the ESF building ventilation system, Emergency Generator Enclosure ventilation system, Service Water Pumphouse ventilation system, and Hydrogen Recombiner building ventilation system were evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Unit 2 and 3, dated August 1, 2005 defines the scope of license renewal. NUREG-1838 Sections 2.3B.3.28, 2.3B.3.27, 2.3B.3.19, 2.3B.3.30, and 3.3B are applicable to the ESF building ventilation system, Emergency Generator Enclosure ventilation system, Service Water Pumphouse ventilation system, and Hydrogen Recombiner building ventilation system.

2.7.6.2 Technical Evaluation

2.7.6.2.1 Introduction

The safety-related ventilation system functions to maintain temperatures within specified limits in areas containing safety-related equipment. Normal ventilation exhausts from potentially contaminated areas are filtered and the discharge is monitored for radiation. Included in the scope of the safety-related ventilation system are the following subsystems:

- Engineered Safety Features Building Ventilation System (FSAR Section 9.4.5)
- Diesel Generator Building Ventilation System (FSAR Section 9.4.6)
- Service Water Pumphouse Ventilation System (FSAR Section 9.4.8)
- Hydrogen Recombiner Building Ventilation System (FSAR Section 9.4.11)

The ESF building ventilation system consists of normal (non-safety-related) and emergency (safety-related) ventilation systems. The normal ventilation system has three sets of supply/exhaust fans.

The first set serves:

- Safety injection pump and quench spray pump areas
- Residual heat removal pump and heat exchanger areas
- Refueling water storage tank recirculation pump area
- Motor driven auxiliary feed water pump areas
- Turbine driven auxiliary feed water pump area
- Containment recirculation pump and cooler areas

The second set serves:

- Quench spray piping cubicles
- Recirculation spray piping cubicles

The third set serves the HVAC mechanical equipment rooms.

The main steam valve piping tunnel for the turbine driven auxiliary feed pump steam isolation valves is equipped with an enclosed air-conditioning unit.

The ESF building emergency ventilation system consists of the following five safety-related ventilation subsystems:

1. Two redundant subsystems serving the residual heat exchanger area, residual heat removal pump area, safety injection and quench spray pump area systems served by self-contained air-conditioning units.

2. Two redundant subsystems serving the containment recirculation pump and cooler area systems served by self-contained air-conditioning units.

3. One subsystem serving the mechanical room and auxiliary feedwater pump areas system served by redundant supply and exhaust fans.

The Emergency Generator Enclosure ventilation system provides emergency ventilation to the diesel generators which are housed in adjacent but separate rooms, each of which is serviced by a safety-related ventilation system having two inlet fans supplying outside or mixed air. Excess air is discharged to the outdoors through automatic, pressure-actuated room vents, backdraft dampers, and wall-mounted louvers. No refrigeration or service water air cooling is used. The exhaust air is forced by supply air out through the exhaust dampers and then through the muffler enclosure to the outdoors. The ventilation ductwork equipped with tornado dampers and is seismically supported.

The Service Water Pumphouse ventilation system provides emergency ventilation to the service water pumps which are housed in adjacent separate rooms. Each room has its own safety-related ventilation system which consists of supply and exhaust fans that supplies and exhausts air through air inlets and discharges located on the roof.

The Hydrogen Recombiner building ventilation system is a safety-related QA Category I system consisting of a ventilation fan which is an integral component of the hydrogen recombiner skid-mounted package, supply and exhaust duct networks, a radiation monitor, and isolation dampers, all powered from a Class 1E power supply. During normal plant operation, the two redundant hydrogen recombiners skid-mounted package systems are not used. Use of the systems is also not credited following a design basis accident (FSAR Section 9.4.11.2).

2.7.6.2.2 Description of Analyses and Evaluations

The changes in heat loads for ventilation subsystems in areas served by the safety-related ventilation system were evaluated to ensure that the ventilation systems are capable of performing their intended functions under SPU conditions, including the ability of the system to circulate sufficient air to prevent accumulation of flammable or explosive gases, or to impact its ability to control airborne particulate material accumulation.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for the ESF ventilation systems. Portions of the safety-related ventilation systems are within the scope of license renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Because no modifications are necessary for safety-related ventilation systems components, SPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.7.6.2.3 Results

The ESF building area temperature does not increase after implementation of the SPU. The insignificant increase in heat load in these buildings is primarily due to the changes in the piping systems operating conditions.

The diesel generator loading is not increased after implementation of the SPU (refer to Section 2.3.3, AC Onsite Power System). Therefore, the ventilation system's ability to provide the required temperature conditions for personnel and equipment is not impacted for SPU.

The service water pump's loading is not increased after implementation of the SPU. Therefore, the ventilation system's ability to provide the required temperature conditions for personnel and equipment is not impacted for SPU.

The hydrogen recombiner loading is not increased after implementation of the SPU. Therefore, the ventilation system's ability to provide the required temperature conditions for personnel and equipment is not impacted for SPU.

The evaluation of the plant equipment changes for the proposed SPU did not identify any need to modify the safety-related ventilation systems. There are no equipment changes as a result of SPU that could affect the accumulation of flammable or explosive vapors or create a new potentially unmonitored radioactive release path.

2.7.6.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the ESF ventilation systems. DNC concludes that the evaluation has adequately accounted for the effects of the proposed SPU on the systems capability to maintain ventilation in the ESF building, Emergency Generator Enclosure, Service Water Pumphouse, and Hydrogen Recombiner building. Based on this, DNC concludes that the ESF building ventilation, Emergency Generator Enclosure ventilation, Service Water Pumphouse ventilation, and Hydrogen Recombiner building ventilation systems will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-4, -17, and -60 following SPU implementation. Therefore, DNC finds the proposed SPU acceptable with respect to the ESF ventilation system.

2.7.7 Other Ventilation Systems (Containment)

2.7.7.1 Regulatory Evaluation

The functions of the Containment structure ventilation system are to provide heat removal from the containment atmosphere and to remove radioactive materials from the containment atmosphere. The DNC review of the Containment structure ventilation system focused on the effects that the proposed SPU will have on the system functional performance.

The acceptance criteria for the review are

- GDC-2*,* insofar as it requires that safety-related structures, systems, and components be designed to accommodate the effects of withstanding the effects of earthquakes*.*

There is no NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, SRP section for containment ventilation and no guidance provided in RS-001.

MPS3 Current Licensing Basis

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants,10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the GDC is discussed in FSAR Sections 3.1.1 and 3.1.2.

The adequacy of MPS3 Station design relative to conformance to:

- GDC-2 is described in the FSAR Section 3.1.2.4, Design Bases for Protection Against Natural Phenomena (Criterion 2).

  Those features of plant facilities that are essential either to the prevention of accidents that could affect the public health and safety or to the mitigation of accident consequences are designed to:

  1. Quality standards that reflect the importance of the function to be performed. Approved design codes are used when appropriate to the nuclear application.

  2. Performance standards that enable the facility to withstand, without loss of the capability to protect the public, the additional forces imposed by the most severe earthquake, flooding condition, wind, ice, or other natural phenomena for the site, as well as credible combinations of the normal and accident conditions with the effect of the natural phenomena.

Additional details that define the licensing basis for the Containment structure ventilation system are described in FSAR Section 9.4.7, Containment Structure Ventilation System.

Technical Specification 3/4.6.1.5, Containment Systems Air Temperature, ensures that the primary containment average air temperature is maintained greater than or equal to 80°F and less than or equal to 120°F.

Technical Specification 3/4.6.1.7, Containment Ventilation System, ensures that excessive quantities of radioactive materials will not be released via the containment purge system. In addition, to provide assurance that the containment purge supply and exhaust isolation valves cannot be inadvertently opened, the valves are locked closed in accordance with SRP 6.2.4.

The Containment structure ventilation subsystems were evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal Millstone Power Station, Units 2 and 3, dated August 1, 2005 defines the scope of license renewal. NUREG-1838 Sections 2.3B.3.20, 3.21, 3.22, 3.26 and 3.3B are applicable to the Containment structure ventilation subsystems.

2.7.7.2 Technical Evaluation

2.7.7.2.1 Introduction

The containment ventilation systems are described in FSAR Section 9.4.7.

The containment ventilation system is designed to accomplish the following:

- Maintain the bulk air temperature in the containment suitable for personnel and equipment operation during normal plant operation and for equipment operation following loss of offsite power.
- Provide sufficient air circulation and filtering throughout all containment areas by reducing the containment atmosphere I-131 concentration to below 1 EC (effluent concentration) to permit safe and continuous access to the reactor containment within 16 hours using one (1) filter unit during normal plant operation and shutdown conditions.
- Maintain the containment average temperature below 95°F during normal plant operation.
- Maintain the containment average air temperature below 135°F during a loss of offsite power.
- Provide for purging the containment to reduce the airborne radioactivity and provide outdoor air during extended periods of occupancy, such as refueling.

Included within the scope of the containment ventilation system are the following subsystems:

- Containment air filtration subsystem
- Containment air recirculation subsystem
- Containment purge air subsystem
- Control rod drive mechanism ventilation and cooling subsystem

The principal components of the containment ventilation system include filters, fans, dampers, valves, heat exchangers, and essential ductwork, containment isolation valves, and piping. The containment recirculation fans, control rod drive mechanism fans, and filtration unit fans are direct-driven units.

The containment air filtration system filters the containment atmosphere, reducing the concentration of airborne radioactive particulates and iodine, permitting a more rapid containment access. The containment air filtration system consists of two 100 percent capacity filter banks with respective ductwork, fans, and a bypass duct. When one fan fails to operate, the redundant fan and filter are manually placed in operation.

The containment air recirculation ventilation system is designed to maintain bulk air temperature in containment suitable for personnel and equipment operation during normal plant operation and loss of offsite power. The system consists of three unit coolers, each with an associated fan. Two of the three fans and coolers are required to provide sufficient capacity to maintain the containment air temperature within design limits during normal plant operation and after a loss of offsite power. Two out of three of the containment recirculation fan cooler electrical connections and other equipment in the containment necessary for operation of the system are capable of operating under the environmental conditions following a loss of offsite power.

The containment purge air system is designed to reduce airborne radioactivity in containment (post reactor shutdown) and provide outside air during extended periods of occupancy (e.g., refueling). The system is independent of the main Auxiliary building exhaust system and includes provisions for both supply and exhaust air. The supply system includes an outside air connection to roughing filters, heating coils, fans, duct system, and supply penetration with a butterfly isolation valve both outside and inside containment. The exhaust system includes an exhaust penetration with a butterfly isolation valve inside and outside containment, a duct system, the Auxiliary building filter banks with high-efficiency particulate air and charcoal filters, exhaust fans, and a Turbine building exhaust vent stack.

The control rod drive mechanism ventilation system maintains CRDM coils below the maximum allowable temperature during normal reactor operation. The system consists of three 50 percent capacity fans, cooling coils, and ductwork. The fans draw air through the control rod drive mechanism shroud, and cooling coils, and then discharge the cooled air back to the containment atmosphere.

2.7.7.2.2 Description of Analyses and Evaluations

The changes in heat loads for ventilation subsystems in the Containment were evaluated to ensure that the ventilation systems are capable of performing their intended functions under normal SPU modes.

Other evaluations related to the containment ventilation system are addressed in the following sections:

- Section 2.8.4.1, Functional Design of the Control Rod Drive System (CRDS), as it relates to CRDM cooling.
- Section 2.6.1, Primary Containment Functional Design, as it relates to containment ventilation isolation.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for the Containment structure ventilation system. Portions of the Containment structure ventilation system are within the scope of license renewal. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating the containment ventilation system at SPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.7.7.2.3 Results

The containment ventilation system's ability to provide the required temperature conditions for personnel and equipment in the Containment during normal operation was evaluated. The results of the evaluation determined that an increase in the containment bulk air temperature of less than 1°F from current observed level will occur at SPU conditions. This increase in the normal operating containment bulk air temperature will not exceed the maximum normal operating bulk temperature limit of 120°F.

As a result of SPU, there will only be minor temperature changes in the process fluids contained in these systems. The minor increase in heat loads can be adequately compensated for by the existing automatic temperature controllers within the cooling systems. Thus, no changes are required for the cooling systems as a result of SPU.

The SPU does not require changes to the containment purge supply and exhaust isolation valves, because the containment peak pressure remains below the containment design pressure of 45 psig (refer to Section 2.6.1, Primary Containment Functional Design). Although technical specifications require these valves to be closed and locked when operating in modes 1-4, operability is based on their ability to adequately isolate the Containment. The ability of the containment purge supply and exhaust isolation valves to provide adequate containment isolation is not impacted by the SPU.

The containment purge system is required to provide sufficient air to purge containment for access and discharge the air via the plant vent. The SPU did not impose any changes on the purge system requirements. Therefore, the containment purge system ability to purge for access is not impacted by the SPU. Radiation monitors are provided to monitor the releases. Refer to LR Section 2.10.1, Occupational and Public Radiation Doses, for the evaluation of the impact on normal releases and the impact on the radiation monitors set-points.

2.7.7.3 Conclusion

DNC has reviewed the evaluation related to the effects of the proposed SPU on the Containment structure ventilation system. DNC concludes that the evaluation adequately accounted for the effects of the proposed SPU on the ability of the Containment structure ventilation system to provide a suitable and controlled environment for the containment components. Based on this, DNC concludes that the Containment structure ventilation system will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-2. Therefore, DNC finds the proposed SPU acceptable with respect to the Containment structure ventilation system.

2.8 Reactor Systems

2.8.1 Fuel System Design

2.8.1.1 Regulatory Evaluation

The fuel system consists of an array of fuel rods, burnable poison rods, spacer grids and springs, end plates, and reactivity control rods. DNC reviewed the fuel system to ensure that:

- The fuel system is not damaged as a result of normal operation and AOOs
- Fuel system damage is never so severe as to prevent control rod insertion when it is required
- The number of fuel rod failures is not underestimated for postulated accidents
- Coolability is always maintained

DNC's review covered fuel system damage mechanisms, limiting values for important parameters, and performance of the fuel system under normal operation, AOOs, and postulated accidents.

The acceptance criteria are based on:

- 10 CFR 50.46, insofar as it established standards for the calculation of ECCS system performance and acceptance criteria for that calculated performance
- GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of AOOs
- GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained
- GDC-35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA

Specific review criteria are contained in SRP Section 4.2, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), Section 4.2, Rev. 2.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to:

- 10 CFR 50.46, Acceptance Criteria for ECCS for Light Water Nuclear Power Reactors, are described in FSAR Section 6.3.3. FSAR Section 6.3.3 provides a design evaluation against 10 CFR 50.46 criteria.
- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.10.

The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant clean up system to mitigate, and are consistent with plant design bases.

2. Ensure return of the reactor to a safe shutdown state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

   Note that the term "fuel damage" as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

   FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-27, Combined Reactivity Control Systems Capability, is described in FSAR Section 3.1.2.27.

  MPS3 is provided with a means of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. FSAR chapters 4 and 9 discuss these means in detail. Combined use of the rod cluster control system and the chemical shim control system permit the necessary shutdown margin to be maintained during long-term xenon decay and plant cooldown. The single highest worth control cluster is assumed to be stuck full out upon trip for this determination. FSAR Chapter 15 describes accident assumptions in detail.

- GDC-35, Emergency Core Cooling, is addressed in FSAR Section 3.1.2.35.

  An ECCS is provided to cope with any LOCA in the plant design basis. Abundant cooling water is available in an emergency to transfer heat from the core at a rate such that the core is maintained in a coolable geometry and that the clad-metal reaction is limited to less than one per cent. Adequate design provisions are made to assure performance of the required safety functions even with a single failure.

FSAR Section 6.3 includes details of the capability of the systems. FSAR Chapter 15 includes an evaluation of the adequacy of the system functions. Performance evaluations are conducted in accordance with 10 CFR 50.46 and 10 CFR 50, Appendix K.

FSAR Section 4.2 describes fuel system design. It addresses mechanical design of the reactor core components and their physical arrangement.

MPS3 was evaluated for continued acceptability to support plant license renewal. NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3", dated August 1, 2005, documents the results of that review. NUREG-1838 does not explicitly address the MPS3 fuel system. The reload safety evaluation process, which is performed for each fuel cycle, provides evaluation and analysis to confirm that the fuel assembly mechanical design, core design, and thermal hydraulic safety analyses are acceptable for the proposed operating cycle. Since this evaluation is performed for each fuel cycle, it represents a continuous review of the fuel system.

2.8.1.2 Technical Evaluation

2.8.1.2.1 Introduction

The FSAR Section 4.2 describes the fuel system design and licensing basis. MPS3 uses the Westinghouse 17x17 RFA/RFA-2 fuel design. No changes have been made to the currently used MPS3 fuel design for the SPU.

Fuel rod performance for all MPS3 fuel is shown to satisfy the NRC SRP fuel rod design bases on a region-by-region basis. These same bases are applicable to all fuel rod designs, including the Westinghouse RFA/RFA-2 fuel design. The design bases for Westinghouse 17x17 RFA/RFA-2 fuel is discussed in Reference 1. The evaluation of fuel rod performance at SPU conditions is based on the same methods and models (PAD 4.0) used in the current licensing basis. Compliance with the GDC-10 SAFDL criteria for reload cycles is confirmed via the approved reload methodology of WCAP-9273-NP-A (Reference 2).

2.8.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Mechanical Performance

The effects of the SPU on the fuel mechanical design are limited to induced changes in the core flow rates and operating temperatures. The impacts of these changes on the fuel have been analyzed. The fuel design analyses that could be impacted are the fuel assembly lift forces and hold down force margin. Analyses have been performed to demonstrate that the fuel assembly lift force margin requirement is met for the SPU without any modifications to the current RFA/RFA-2 fuel assembly design. The analyses and testing that have been performed confirm that the RFA/RFA-2 design and associated core components including RCCAs are structurally and mechanically acceptable for the MPS3 SPU operation.

Seismic/LOCA

The effects of the SPU on the seismic/LOCA performance of the fuel mechanical design have been analyzed to confirm that all acceptance criteria and regulatory requirements are met. The criteria for the seismic loading design are that fragmentation of the fuel rod must not occur as a result of the seismic loads and the ability to insert control rods must be maintained. In addition, coolable geometry of the core must be maintained. The principal acceptance criteria for a LOCA event are that fragmentation of the fuel rod must not occur as a direct result of the blowdown load and the ability to insert control rods must be satisfied. Likewise, coolable geometry of the core must be maintained.

Fuel Rod Performance

The fuel rod design analysis is performed on a cycle-specific basis. The reference analysis presented here is based on the bounding high-temperature nuclear design cases representing three cycles at SPU conditions (two power transition cycles and one equilibrium cycle) developed for the Nuclear Design (see Section 2.8.2, Nuclear Design). Both the reference analysis and the cycle-specific analysis consider compliance for all fuel designs in the core. The mechanical fuel rod design evaluation for each region incorporates all appropriate design features of the region, including any changes to the fuel rod or pellet geometry from that of previous fuel regions (for example, the presence of annular pellets in axial blankets or changes in the fuel rod diameter and plenum length). Analysis of integral fuel burnable absorber (IFBA) rods includes any geometry changes necessary to model the presence of the burnable absorber, and conservatively models the gas release from the ZrB_2 coating.

Fuel rod design evaluations for the 17x17 RFA/RFA-2 fuel were performed using NRC-approved models (References 1 and 3) and NRC-approved design criteria methods (References 4 and 5) to demonstrate that all fuel rod design criteria are satisfied.

The fuel rod design criteria given below are verified by evaluating the predicted performance of the limiting fuel rod, defined as the rod that gives the minimum margin to the design limit. In general, no single rod is limiting with respect to all the design criteria. Generic evaluations alone cannot identify which rods are most likely to be limiting for each criterion. An exhaustive screening of fuel rod power histories and fuel rods was used to determine the limiting rod.

The NRC-approved PAD 4.0 code, with NRC-approved models (References 1 and 3) for in-reactor behavior, is used to calculate the fuel rod performance over its irradiation history. PAD is the principal design tool for evaluating fuel rod performance. PAD iteratively calculates the interrelated effects of temperature, pressure, clad elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power.

PAD 4.0 is a best-estimate fuel rod performance model, and in most cases the design criterion evaluations are based on a best-estimate plus uncertainties approach. A statistical convolution of individual uncertainties due to design model uncertainties and fabrication dimensional tolerances is used. As-built dimensional uncertainties are measured for some critical inputs, for example, fuel pellet diameter, when available, can be used in lieu of the fabrication uncertainties.

An evaluation of the clad and structural component oxidation and hydriding was also performed.

The criteria applicable to the fuel rod design are:

- Rod Internal Pressure

  The internal pressure of the lead fuel rod in the reactor is limited to a value below that which could cause the diametral gap to increase due to outward clad creep during steady-state operation or extensive DNB propagation to occur.

- Clad Stress and Strain

  The design limit for clad stress is that the volume average effective stress considering interference due to uniform cylindrical pellet-to-clad contact caused by pellet thermal expansion, pellet swelling, and uniform clad creep, and pressure differences between the rod internal pressure and the system coolant pressure are less than the clad yield strength for Condition I and II events. While the clad has some capability for accommodating plastic strain, the yield stress has been established as the conservative design limit. The design limit for clad strain during steady-state operation is that the total plastic tensile creep strain due to uniform clad creep and uniform cylindrical fuel pellet expansion associated with fuel swelling and thermal expansion is less than 1 percent from the unirradiated condition. The design limit for fuel rod clad strain during Condition II events is that the total tensile strain due to uniform cylindrical pellet thermal expansion is less than 1 percent from the pre-transient value. These limits are consistent with proven practice.

- Clad Oxidation and Hydriding

  The design criteria related to clad corrosion require that the Zircaloy-4/ZIRLO^{TM} clad metal-oxide interface temperature is maintained below specified limits to prevent a condition of accelerated oxidation, which would lead to clad failure.

  The best-estimate hydrogen pickup level in Zircaloy-4/ZIRLO^{TM} clad and Zircaloy-4/ZIRLO^{TM} structural components is less than or equal to the limit on a volume average basis at EOL.

- Fuel Temperature

  For Condition I and II events, the fuel and reactor protection systems are designed to ensure that a calculated centerline fuel temperature does not exceed the fuel melting temperature criterion. The intent of this criterion is to avoid a condition of gross fuel melting that can result in severe duty on the clad. The concern here is based on the large volume increase associated with the phase change in the fuel, and the potential for loss-of-clad integrity as a result of molten fuel/clad interaction.

- Clad Fatigue

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

- Clad Flattening

  The clad flattening criterion prevents fuel rod failures due to long-term creep collapse of the fuel rod clad into axial gaps formed within the fuel stack. Current fuel rod designs employing fuel with improved in-pile stability provides adequate assurance that axial gaps large enough to allow clad flattening do not form within the fuel stack.

- Fuel Rod Axial Growth

  This criterion ensures that there is sufficient axial space to accommodate the maximum expected fuel rod growth without degradation of the assembly function. Fuel rods are designed with adequate clearance between the fuel rod and the top and bottom nozzles to accommodate the differences in the growth of fuel rods and the growth of the fuel assembly to preclude interference of these members.

- Plenum Clad Support

  This criterion ensures that the fuel clad in the plenum region of the fuel rod do not collapse during normal operating conditions, nor distort so as to degrade fuel rod performance.

- Clad Free-Standing

  The clad criterion requires that the clad is short-term, at beginning of life (BOL), at power, and during hot hydrostatic testing. This criterion precludes the instantaneous collapse of the clad onto the fuel pellet caused by the pressure differential that exists across the clad wall.

  The specific assumptions used in the verification of these criteria for the MPS3 fuel include: MPS3 SPU specific operating conditions, and fuel rod duty (steady-state powers, fuel rod axial power shapes, etc.).

2.8.1.2.3 Description of Analyses and Evaluations

Mechanical Performance

With respect to the mechanical performance of the fuel, the impacts on the fuel of the core flow rates and operating temperatures changes have been analyzed. The fuel design analyses that could be impacted are the fuel assembly lift forces and hold down force margin. Analyses have been performed to demonstrate that the fuel assembly lift force margin requirement is met for the SPU without any modifications to the current RFA/RFA-2 fuel assembly design. The hold down force calculation conservatively assumed high burnup fuel assembly growth (75,000 MWD/MTU peak rod burnup) and hold down spring relaxation due to irradiation effects. The analysis accounted for the opposing forces that act on the fuel assemblies due to fuel assembly weight, buoyancy, spring force, and lift force.

Seismic/LOCA

The results of the combined LOCA and seismic analysis were obtained using the time-history numerical integration technique. The maximum grid impact forces obtained from both transients were combined using the square root of the sum of squares method. The maximum loads were compared with the allowable grid crush strength. In the grid load analysis, the time-history motions of the barrel at the upper core plate elevation and the upper and lower core plates were applied simultaneously to the reactor core model. The time histories representing the seismic motion and the pipe rupture transients were obtained from the time history analyses of the reactor vessel and internals finite element model. Differences in characteristics between the RFA/RFA-2 and VANTAGE 5H fuel designs were considered in the evaluation for acceptability of re-insertion of previously irradiated VANTAGE 5H assemblies.

Fuel Rod Performance

- Rod Internal Pressure

  The rod internal pressure for the MPS3 fuel rods has been evaluated by modeling the gas inventories, gas temperature, and rod internal volumes through the rods' life. The resulting rod internal pressure is compared to the design limit on a case-by-case basis of current operating conditions to EOL. This evaluation showed that the rod internal pressure satisfies the design limit.

  The second part of the rod internal pressure design basis precludes extensive DNB propagation and associated fuel failure. The basis for this criterion is that no significant additional fuel failures, due to DNB propagation, occur in cores that have fuel rods operating with rod internal pressure in excess of system pressure. The design limit for Condition II events is that DNB propagation is not extensive, that is, the process is shown to be self-limiting and the number of additional rods in DNB due to propagation is relatively small. For Condition III/IV events, it is shown that the total number of rods in DNB, including propagation effects, is consistent with the assumptions used in radiological dose calculations for the event under consideration.

- Clad Stress and Strain

  Clad temperature and irradiation effects on yield strength were considered in the analysis. The clad stress criterion has been shown to meet the design limits by use of a statistical method that takes into account many uncertainties. Transient clad strain is met based on the clad stress results as described in the previous section. Steady state clad strain is met by using a MPS3 SPU specific calculation.

- Clad Oxidation and Hydriding

  The clad surface temperatures were evaluated and satisfied the applicable temperature limits. The base metal wastage of the Zircaloy-4 and ZIRLO^{TM} grids and guide tubes were shown not to exceed the design limit at EOL.

  The hydrogen pickup criterion, which limits the loss of ductility due to hydrogen embrittlement that occurs upon the formation of zirconium hydride platelets, has been met with the current approved model for the MPS3 SPU.

- Fuel Temperature

  The temperature of the fuel pellets was evaluated by modeling the fuel rod geometry, thermal properties, heat fluxes, and temperature differences in order to calculate fuel surface, average, and centerline temperatures of the fuel pellets.

Fuel temperatures have been calculated as a function of local power and burnup. The fuel surface and average temperatures with associated rod internal pressure are used in accident and transient analyses of the 17x17 RFA/RFA-2 fuel design. The fuel centerline temperatures are used to show that fuel melt does not occur. For the 17x17 RFA/RFA-2 design, the local linear power that precludes fuel centerline melting is 22.60 kW/ft.

- Clad Fatigue

  Clad fatigue for the 17x17 RFA/RFA-2 fuel was evaluated by using a limiting fatigue duty cycle consisting of daily load follow maneuvers. The 17x17 RFA/RFA-2 fuel rod fatigue evaluation, based on a statistical method that takes into account many uncertainties, showed that the cumulative fatigue usage factor is less than the design limit of 1.0.

- Clad Flattening

  The NRC has approved WCAP-13589-A (Reference 5), which provided data to confirm that significant axial gaps in the fuel column due to densification (and therefore clad flattening) do not occur in current Westinghouse fuel designs. The MPS3 fuel meets the criteria for applying the reference 5 methodology and, therefore, clad flattening does not occur.

- Fuel Rod Axial Growth

  The MPS3 SPU fuel rod growth evaluation demonstrates that there is adequate margin to the fuel rod growth design limit for the 17x17 RFA/RFA-2 fuel.

- Plenum Clad Support

  The helical coil spring used in the 17x17 RFA/RFA-2 fuel design for the MPS3 SPU has been shown to provide enough support to prevent potential clad collapse. Therefore, the plenum clad support criterion is met for the 17 x 17 RFA/RFA-2.

- Clad-Free Standing

  Evaluations of the clad-free standing criteria have shown that instantaneous collapse of the MPS3 fuel is precluded for differential pressures well in excess of the maximum expected differential pressure across the clad under operating conditions. This generic analysis has been shown to be met for all Westinghouse fuel rod geometries.

Fuel rod design evaluations for MPS3 are performed using the NRC approved models in references 1 and 3 to demonstrate that the SRP fuel rod design criteria are satisfied. For the 17x17 RFA/RFA-2 fuel design, these criteria are satisfied. The fuel rod design code and methodology used for the MPS3 SPU analyses was previously approved by the NRC (References 3 and 6).

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the Fuel System Design. As stated in Section 2.8.1.1, NUREG-1838 does not explicitly address the MPS3 fuel system. The reload safety evaluation process, which is performed for each fuel cycle, provides evaluation and analysis to confirm that the fuel assembly mechanical design, core design, and thermal hydraulic safety analyses are acceptable for the proposed operating cycle. Since this evaluation is performed for each fuel cycle, it represents a continuous review of the fuel system.

2.8.1.2.4 Results

Mechanical Performance

With respect to the mechanical design of the fuel, the analyses and testing that have been performed confirm that the RFA/RFA-2 design is structurally and mechanically acceptable for the MPS3 SPU operation. Use of re-inserted previously irradiated VANTAGE 5H assemblies is also acceptable for SPU operation.

Seismic/LOCA

The results of the combined seismic and LOCA analyses indicate that the maximum impact forces are less than the respective allowable grid strengths. The allowable grid strengths are established at the 95 percent confidence level on the true mean from the distribution of experimentally determined grid crush data at temperature. Based on the results of the combined seismic and LOCA loads, the 17x17 RFA/RFA-2 design is structurally acceptable for the MPS3 SPU and the core coolable geometry requirements are met. Re-insertion of previously irradiated VANTAGE 5H assemblies is also acceptable under seismic and LOCA loads for the MPS3 SPU operation.

Fuel Rod Performance

Fuel performance evaluations have been completed for each fuel region to demonstrate that the design criteria can be satisfied for all fuel rod types in the core under the planned operating conditions of a core power uprating to 3650 MWt. Based on input from core design, the fuel rod design was analyzed with an F_H^N limit of 1.65 for the 17x17 RFA/RFA-2 fuel.

Each of the key fuel rod design criteria has been evaluated for application of the Westinghouse 17x17 RFA/RFA-2 fuel assembly design in MPS3. Based on these evaluations, it is concluded that each design criterion is satisfied for the 17x17 RFA/RFA-2 design.

2.8.1.3 Conclusion

DNC has reviewed the analyses related to the effects of the proposed SPU on the fuel system design of the fuel assemblies, control systems, and reactor core. DNC concludes that the analyses have adequately accounted for the effects of the proposed SPU on the fuel system and demonstrated that 1) the fuel system will not be damaged as a result of normal operation and AOOs, 2) the fuel system damage will never be so severe as to prevent control rod insertion when it is required, 3) the number of fuel rod failures will not be underestimated for postulated accidents, and 4) coolability will always be maintained. Based on this, DNC concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, GDC-10, GDC-27, and GDC-35 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the fuel system design.

2.8.1.4 References

1. Davidson, S. L., Nuhfer, D. L.,“VANTAGE+ Fuel Assembly Reference Core Report,” WCAP-12610-P-A, April 1995.

2. Davidson, S. L. (Ed.), et al., “Westinghouse Reload Safety Evaluation Methodology,” WCAP-9273-NP-A, July 1985.

3. WCAP-15063-P-A, Rev. 1 with Errata (Proprietary), Foster, Sidener, and Slagle, Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), July 2000.

4. WCAP-10125-P-A (Proprietary), Davidson, S. L., et al., Extended Burnup Evaluation of Westinghouse Fuel, December 1985.

5. WCAP-13589-A, Kersting, P. J., et al., Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel, March 1995.

6. WCAP-15064-NP-A, Rev. 1 (Nonproprietary), Foster, Sidener, and Slagle, Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), July 2000.

2.8.2 Nuclear Design

2.8.2.1 Regulatory Evaluation

DNC reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the reactor coolant pressure boundary or impair the capability to cool the core. The DNC review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation.

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of AOOs
- GDC-11, insofar as it requires that the reactor core be designed so that the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity
- GDC-12, insofar as it requires that the reactor core be designed to ensure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can be reliably and readily detected and suppressed
- GDC-13, insofar as it requires that instrumentation and controls be provided to monitor variables and systems affecting the fission process over anticipated ranges for normal operation, AOOs and accident conditions, and to maintain the variables and systems within prescribed operating ranges
- GDC-20, insofar as it requires that the protection system be designed to automatically initiate the reactivity control systems to ensure that acceptable fuel design limits are not exceeded as a result of AOOs and to automatically initiate operation of systems and components important-to-safety under accident conditions
- GDC-25, insofar as it requires that the protection system be designed to ensure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems
- GDC-26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes
- GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to ensure the capability to cool the core is maintained
- GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB

greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core

Specific review criteria are contained in SRP Section 4.3, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), Section 4.3, Rev. 2.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to conformance to:

- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

  1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant clean up system to mitigate, and are consistent with plant design bases.

  2. Ensure return of the reactor to a safe shutdown state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

  3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

  Note that the term "fuel damage" as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

  FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-11, Reactor Inherent Protection, is described in FSAR Section 3.1.2.11.

  Prompt compensatory reactivity feedback effects are assured when the reactor is critical by the negative fuel temperature effect (Doppler effect) and by ensuring that the moderator temperature coefficient is maintained within the limits provided in Technical Specification 3/4.1.1.3. FSAR Section 4.3.2.3 discusses these reactivity coefficients.

- GDC-12, Suppression of Reactor Power Oscillations, is described in FSAR Section 3.1.2.12.

  Total power oscillations of the fundamental mode are inherently stable by the negative power coefficient of reactivity.

  Oscillations, due to xenon spatial effects, in the radial, diametral, and azimuthal overtone modes are heavily damped due to the inherent design and due to the negative power coefficient of reactivity.

  Oscillations, due to xenon spatial effects, in the axial first overtone mode may occur. Assurance that the fuel design limits are not exceeded by xenon axial oscillations is provided by reactor trip functions using the measured axial power imbalance as an input.

  Oscillations, due to xenon spatial effects, in the axial modes higher than the first overtones are heavily damped due to the inherent design and due to the negative Doppler coefficient of reactivity. FSAR Section 4.3 discusses xenon and samarium stability control.

- GDC-13, Instrumentation and Control, is described in FSAR Section 3.1.2.13.

  Instrumentation and controls are provided to monitor and control neutron flux, control rod position, temperatures, pressures, flows and levels as necessary to assure that adequate plant safety can be maintained. Instrumentation is provided in the reactor coolant system, steam and power conversion system, the containment, engineered safety features systems, and other auxiliaries. Parameters that must be provided for operator use under normal operating and accident conditions are indicated in proximity with the controls for maintaining the indicated parameter in the proper range.

  The quantity and types of processing instrumentation provided ensures safe and orderly operation of all systems over the full design range of the plant. These systems are described in FSAR Chapters 6, 7, 8, 9, 11 and 12.

- GDC-20, Protection System Functions, is described in FSAR Section 3.1.2.20

  A fully automatic protection system, with appropriate redundant channels, is provided to cope with transients where insufficient time is available for manual corrective action. The design basis for all protection systems is IEEE Standard 279-1971 and IEEE Standard 379-1972. The reactor protection system automatically initiates a reactor trip when any variable exceeds the normal operating range. Setpoints are designed to provide an envelope of safe operating conditions with adequate margin for uncertainties to ensure that fuel design limits are not exceeded.

  Reactor trip is initiated by removing power to the rod drive mechanisms of all of the rod cluster control assemblies. This causes the rods to insert by gravity, rapidly reducing the reactor power output. The response and adequacy of the protection system have been verified by analysis of expected transients.

  The ESF actuation system automatically initiates emergency core cooling, and other safeguards functions, by sensing accident conditions using redundant analog channels measuring diverse variables. Manual action of safeguards equipment may be performed where ample time is available for operator action. The ESF actuation system automatically trips the reactor on manual or automatic SIS generation.

- GDC-25, Protections System Requirements for Reactivity Control Malfunctions, is described in FSAR Section 3.1.2.25.

  The protection system is designed to limit reactivity transients so that fuel design limits are not exceeded. Reactor shutdown by rod insertion is completely independent of the normal control function, since the trip breakers interrupt power to the rod mechanisms regardless of existing control signals. Thus, in the postulated accidental withdrawal (assumed to be initiated by a control malfunction), flux, temperature, pressure, level and flow signals would be generated independently. Any of these signals (trip demands) would operate the breakers to trip the reactor.

  FSAR Chapter 15 discusses analyses of the effects of possible malfunctions. These analyses show that for postulated dilution during refueling, startup or manual or automatic operation at power, the operator has ample time to determine the cause of dilution, terminate the source of dilution, and initiate boration before the shutdown margin is lost. The analyses show that acceptable fuel damage limits are not exceeded even in the event of a single malfunction of either system.

- GDC-26, Reactivity Control System Redundancy and Capability, is described in FSAR Section 3.1.2.26.

  Two reactivity control systems are provided. These are RCCAs and chemical shim (boric acid). The RCCAs are inserted into the core by the force of gravity.

  During operation the shutdown rod banks are fully withdrawn. The rod control system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specific fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses, and the most reactive rod cluster is assumed to be in the fully withdrawn position.

  The CVCS maintains the reactor in the cold shutdown state independent of the position of the control rods. It can compensate for xenon burnout transients.

  FSAR Chapter 4 presents details of the construction of the RCCAs. FSAR Chapter 7 discusses their operation. FSAR Chapter 9 describes the means of controlling boric acid concentration. FSAR Chapter 15 includes performance analyses under accident conditions.

- GDC-27, Combined Reactivity Control Systems Capability, is described in FSAR Section 3.1.2.27.

  MPS3 is provided with a means of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. FSAR Chapters 4 and 9 discuss these means in detail. Combined use of the rod cluster control system and the chemical shim control system permits the necessary shutdown margin to be maintained during long term xenon decay and plant cooldown. The single highest worth control cluster is assumed to be stuck full-out upon trip for this determination. FSAR Chapter 15 describes accident assumptions in detail.

- GDC-28, Reactivity Limits, is described in FSAR Section 3.1.2.28.

  The maximum reactivity worth of control rods and the maximum rate of reactivity insertion employing control rods are limited to values that prevent rupture of the RCS boundary or disruption of the core or vessel internals to a degree that could impair the effectiveness of emergency core cooling.

  The maximum positive reactivity insertion rates for the withdrawal of RCCAs and the dilution of the boric acid in the RCS are limited by the physical design characteristics of the RCCAs and of the CVCS. TS on shutdown margin and on RCCA insertion limits and bank overlaps as functions of power provide additional assurance that the consequences of the postulated accidents are no more severe than those presented in the analyses of FSAR Chapter 15. Reactivity insertion rates, dilution, and withdrawal limits are also discussed in FSAR Section 4.3. The capability of the CVCS to avoid an inadvertent excessive rate of boron dilution is discussed in FSAR Section 15.

  Assurance of core cooling capability following Condition IV accidents, such as rod ejections, steam line breaks, etc., is given by keeping the RCPB stresses within faulted condition limits as specified by applicable ASME codes. Structural deformations are checked also and limited to values that do not jeopardize the operation of necessary safety features.

FSAR Section 4.3 describes the design bases and functional requirements used in the nuclear design of the fuel and reactivity control system.

A review of fuel system design for the impact on license renewal applications was not necessary since each new core is treated as a design change. A reload analysis is performed prior to each refueling outage. The reload safety evaluation process provides evaluation and analysis to confirm that the fuel design, core design, and safety analyses are acceptable for the proposed operating cycle. The reload design methodology includes the evaluation of the reload core key safety parameters which comprise the nuclear design-dependent input to the FSAR safety evaluation for each fuel cycle.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Design aspects of systems and components are addressed in other licensing report sections. Specific transient analysis is not within the scope of License Renewal.

2.8.2.2 Technical Evaluation

2.8.2.2.1 Introduction

The licensing basis for the reload core nuclear design is defined in FSAR Section 4.3. The purpose of the core analysis is to determine prior to the cycle-specific reload design if the previously used values for the key safety parameters remain applicable to the plant uprating.

This allows the majority of any safety analysis re-evaluations/re-analyses to be completed prior to the cycle specific design analysis. The effects of the SPU conditions on the nuclear design bases and methodologies for MPS3 are evaluated in this section.

2.8.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The specific values of core safety parameters, e.g., power distributions, peaking factors, rod worths, and reactivity parameters are loading pattern dependent. The variations in loading pattern dependent safety parameters are expected to be similar to the cycle-to-cycle variations for typical fuel reloads.

The reload design methodology includes the evaluation of the reload core key safety parameters which comprise the nuclear design-dependent input to the FSAR safety evaluation for each reload cycle (Reference 1). These key safety parameters are evaluated for each MPS3 reload cycle. If one or more of the parameters fall outside the bounds assumed in the reference safety analysis, the affected transients are re-evaluated/re-analyzed using standard methods and the results documented in the reload evaluation for that cycle.

Table 2.8.2-1 provides the key safety parameter ranges compared to the current limits.

2.8.2.2.3 Description of Analyses and Evaluations

Core loading patterns for three cycles were established using PHOENIX-P and ANC (Reference 2 and 3) to model the MPS3 SPU. Typical loading patterns were developed based on projected energy requirements of approximately 515 EFPDs for MPS3. These models are not intended to represent limiting loading patterns, but were instead developed with the intent to show that enough margin exists between typical safety parameter values and the corresponding limits to allow flexibility in designing actual reload cores. Existing designs (including current designs) were used for comparison to evaluate the continued adequacy of margins between typical safety parameter values and the corresponding limits.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the Nuclear Design. As stated in Section 2.8.1, specific transient analysis is not within the scope of license renewal. Design aspects of systems and components are addressed in other licensing report sections. Therefore, there is no impact on the evaluations performed for License Renewal and they remain valid for the SPU conditions.

2.8.2.2.4 Results

The key safety parameters evaluated for MPS3 as it transitions to the SPU show little change relative to the current design. The changes in values of the key safety parameters are typical of the normal cycle-to-cycle variations experienced as loading patterns change. The specific reload cycle core design is such that it meets all nuclear design criteria at the SPU conditions.

2.8.2.3 Conclusion

DNC has reviewed the analyses related to the effect of the proposed SPU on the nuclear design of the fuel assemblies, control systems, and reactor core. DNC concludes that the analyses have adequately accounted for the effects of the proposed SPU on the nuclear design and has demonstrated that the fuel design limits will not be exceeded during normal or anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. Based on this evaluation and in coordination with the reviews of the fuel system design, thermal and hydraulic design, and transient and accident analyses, DNC concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the applicable requirements of GDCs -10, -11, -12, -13, -20, -25, -26, -27, and -28. Therefore, DNC finds the proposed SPU acceptable with respect to the nuclear design.

2.8.2.4 References

1. Davidson, S. L. (Ed.), et al., “Westinghouse Reload Safety Evaluation Methodology,” WCAP-9273-NP-A, July 1985.

2. Nguyen, T. Q., et al., “Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores,” WCAP-11596-P-A, June 1988.

3. Liu, Y. S., et al., “ANC: A Westinghouse Advanced Nodal Computer Code,” WCAP-10965-P-A, September 1986.

Table 2.8.2-1
Range of Key Safety Parameters Safety Parameter

	Current Design Values	Analysis Values
Reactor Core Power (MWt)	3411	3650
Vessel Average Coolant Temp. HFP (°F)	591.6	581.5 to 589.5[a,b]
Coolant System Pressure (psia)	2250	2250
Core Average Linear Heat Rate (kW/ft)	5.45	5.83
Most Positive MTC (pcm/°F)		
Power < 70%	+ 5.0	+ 5.0
Power $\geq$ 70%	0.0	0.0
Most Positive MDC (K/g/cm3)	0.50	0.50
		0.45[c]
Doppler Temperature Coefficient (pcm/°F)	-3.20 to -0.91	-3.20 to -0.90
Doppler Only Power Coefficient (pcm/%Power)		
Least Negative, 118%RTP to HZP	-9.55 to -5.42	----
Most Negative, 118%RTP to HZP	-19.40 to -11.36	----
Least Negative, 121%RTP to HZP	-11.55 to -7.02	----
Most Negative, 121%RTP to HZP	-19.40 to -11.17	----
Least Negative, 130%RTP to HZP	----	-9.55 to -5.00
Most Negative, 130%RTP to HZP	----	-19.40 to -10.56
Beta-Effective	0.0040 to 0.0070	0.0040 to 0.0075
Normal Operation FNH	1.70	1.65
Normal Operation FQ(Z)	2.60	2.60

Table 2.8.2-1
Range of Key Safety Parameters Safety Parameter

	Current Design Values	Analysis Values
Shutdown Margin (%)	1.30	1.30

a. The vessel average coolant temperature can decrease to 571.5°F during a coast down.
b. Constant temperature program assumed during nominal depletion.
c. Linear ramp from 70% to 100% power.
d. MDC assumed for feedline break analysis (HFP ARO)

2.8.3 Thermal and Hydraulic Design

2.8.3.1 Regulatory Evaluation

The DNC review covered the thermal and hydraulic design of the core and the RCS to confirm that the design:

- Has been accomplished using acceptable analytical methods
- Is equivalent to or a justified extrapolation from proven designs
- Provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and anticipated operational transients
- Is not susceptible to thermal-hydraulic instability

The DNC review of the subject design analyses also covered hydraulic loads on the core and RCS system components during normal operation and DBA conditions and core thermal hydraulic stability under normal operation and condition II events.

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences (AOOs)
- GDC-12, insofar as it requires that the reactor core and associated coolant, control and protection systems be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can be reliably and readily detected and suppressed

Specific review criteria are contained in the SRP Section 4.4, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), Section 4.4, Rev. 1.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to:

- GDC-10, Reactor design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

  1. Assure that fuel damage is not expected during normal core operation and operational; transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant clean up system to mitigate, and are consistent with plant design bases.

  2. Ensure return of the reactor to a safe shutdown state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

  3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

  Note that the term “fuel damage” as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

  FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-12, Suppression of reactor power oscillations, is described in FSAR Section 3.1.2.12.

  Total power oscillations of the fundamental mode are inherently stable by the negative power coefficient of reactivity.

  Oscillations, due to xenon spatial effects, in the radial, diametral, and azimuthal overtone modes are heavily damped due to the inherent design and due to the negative power coefficient of reactivity.

  Oscillations, due to xenon spatial effects, in the axial first overtone mode may occur. Assurance that the fuel design limits are not exceeded by xenon axial oscillations is provided by reactor trip functions using the measured axial power imbalance as an input.

  Oscillations, due to xenon spatial effects, in the axial modes higher than the first overtones are heavily damped due to the inherent design and due to the negative Doppler coefficient of reactivity. FSAR Section 4.3 discusses xenon and samarium stability control.

FSAR Section 4.4 states the following relative to thermal and hydraulic design:

- There will be at least a 95 percent probability that DNBR will not occur on the limiting fuel rods during normal operation and operational transients and any transient arising from faults of moderate frequency (Condition I and II events) at a 95 per cent confidence level. Further information on MPS3 DNBR design is shown in FSAR Section 4.4.1.1.

- During modes of operation associated with Condition I and Condition II events, there is at least a 95 percent probability that the peak kW/ft fuel rods will not exceed the UO_2 melting temperature at the 95 percent confidence level. Further information on MPS3 fuel temperature design is shown in FSAR Section 4.4.1.2.
- With the thimble plug assemblies removed, a minimum of 91.4 per cent of the thermal flow rate will pass through the fuel rod region of the core and be effective for fuel rod cooling. With the thimble plug assemblies installed, a minimum of 93.4 per cent of the thermal flow rate will pass through the fuel regions of the core and be effective for fuel rod cooling. Coolant flow through the thimble tubes, as well as the leakage from the core barrel-baffle region, into the core, are not considered effective for heat removal. Further information on the core flow design is shown in FSAR Section 4.4.1.3
- Modes of operation associated with Condition I and II events shall not lead to hydro-dynamic instability.
- Other conditions for thermal and hydraulic design are discussed in FSAR Sections 4.4.1.5 and 4.4.2.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. The evaluation of core thermal and hydraulic design was not within the scope of License Renewal.

2.8.3.2 Technical Evaluation

2.8.3.2.1 Introduction

This section describes the thermal-hydraulic (T/H) analysis supporting the MPS3 SPU with a full core of 17x17 RFA/RFA-2 fuel assemblies. The current licensing basis for T/H design for MPS3 includes the prevention of DNB on the limiting fuel rod with a 95 percent probability at a 95 percent confidence level and criteria to ensure fuel cladding integrity, and is documented in FSAR Section 4.4. The SPU analysis is based on this licensing basis analysis incorporating the increased core power. The analysis addresses the DNB performance, including the effects of fuel rod bow and bypass flow.

Also considered in this section are:

- The calculation of fuel temperature/pressure data used in various safety analyses, and
- Core stored energy.

2.8.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

VIPRE-01 is the Core Thermal-hydraulic sub-channel analysis code that was used for the SPU analysis. NRC approval of the Westinghouse VIPRE-01 methodology was issued in the SER attached to Reference 1. The MPS3 sub-channel analysis complies with any limitations, restrictions, and conditions specified in Reference 1.

For the purposes of the SPU analysis, bounding fuel-related safety and design parameters have been chosen. These bounding parameters have been used in the safety and design analyses discussed in this section and in other relevant sections of this report.

Table 2.8.3-1 lists the thermal-hydraulic parameters for the current design at 3411 MWt with RFA/RFA-2 fuel, as well as for the SPU design at 3650 MWt with the RFA/RFA-2. Some of the parameters listed in Table 2.8.3-1 are used in the analysis basis as VIPRE-01 input parameters while others are provided since they are listed in the FSAR. This section identifies those parameters that are used as input parameters to the VIPRE-01 model and also identifies the limiting direction of each parameter, which is shown in Table 2.8.3-2. In addition, the average linear power (kW/ft) is used in the PAD analyses for the fuel temperature and the rod internal pressure calculations. The following parameters from Table 2.8.3-1 are used in the VIPRE-01 model:

- Reactor core heat output (MWt)
- Heat generated in fuel (%)
- Nominal vessel/core inlet temperature (°F)
- $F^N_{\Delta H}$, nuclear enthalpy rise hot-channel factor (radial power distribution)
- Pressurizer/core pressure (psia)
- Thermal design flow (gpm)

The thermal-hydraulic design criteria and methods are the same as those presented in the FSAR (Reference 2). While the methods are the same, the VIPRE-01 code was used instead of the THINC IV code for all core thermal-hydraulic safety analyses.

The thermal-hydraulic analysis of the SPU with RFA/RFA-2 fuel in MPS3 is based on the Revised Thermal Design Procedure (RTDP) (Reference 3), the WRB-2M DNB correlation (Reference 4), and the VIPRE-01 code (Reference 1). The NRC SER approving this procedure, correlation, and code is included in the references. The W-3 or WRB-2 correlation and the Standard Thermal Design Procedure (STDP) are used when any one of the conditions is outside the range of the WRB-2M correlation (that is, pressure, local mass velocity, local quality, heated length, grid spacing, equivalent hydraulic diameter, equivalent heated hydraulic diameter, and distance from last grid to critical heat flux (CHF) site) and RTDP (that is, the statistical variance is exceeded on power, core inlet temperature, pressure, flow, bypass, $F^N_{\Delta H}$, $F^E_{\Delta H,1}$, and F^E_Q). The MPS3 thermal-hydraulic analysis complies with any limitations, restrictions, and conditions specified in NRC SERs.

The WRB-2M DNB correlation is based entirely on rod bundle data and takes credit for the significant improvements in DNB performance due to the mixing vane grid effects. NRC acceptance of a 95/95 correlation limit DNBR of 1.14 for the RFA/RFA-2 fuel assemblies is documented in Reference 4.

With the RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are combined statistically to obtain the overall DNB uncertainty factor. This factor is used to determine the plant-specific design limit DNBR that satisfies the DNB design criterion. Since the parameter uncertainties are considered in determining the RTDP design limit DNBR values, the plant safety analyses are performed using input parameters at their nominal values.

The uncertainties included in the overall DNB uncertainty factor are:

- The nuclear enthalpy rise hot channel factor, ($F^{N}_{\Delta H}$)
- The enthalpy rise engineering hot channel factor, ($F^{E}_{\Delta H,1}$)
- Uncertainties in the VIPRE-01 and transient codes
- Vessel coolant flow
- Effective core flow fraction
- Core thermal power
- Coolant temperature
- System pressure

Because the uncertainties are incorporated in the DNBR limit, nominal values of the peaking and hot channel factors are used as input to the DNB safety analyses. Table 2.8.3-3 provides a listing and description of the peaking factor uncertainties.

Instrumentation uncertainties in core thermal power, RCS flow, pressure and temperature used for the SPU analyses, are listed in Table 2.8.3-4. The instrumentation uncertainties were used in determining the DNBR design limits.

The reactor core is designed to meet the following limiting thermal and hydraulic criteria:

A. There is at least a 95 percent probability that DNB will not occur on the limiting fuel rods during MODES 1 and 2 operational transients, or any condition of moderate frequency at a 95 percent confidence level.

B. No fuel melting during any anticipated normal operating condition, operational transients, or any conditions of moderate frequency.

C. Mode of operation under condition I and II events will not lead to thermo-hydro-dynamic instabilities.

The ratio of the heat flux causing DNB at a particular core location, as predicted by a DNB correlation, to the actual heat flux at the same core location is the DNBR. Analytical assurance that DNB will not occur is provided by showing the calculated DNBR to be higher than the 95/95 Limit DNBR for all conditions of normal operation, operational transients and transient conditions of moderate frequency. The Design Limit DNBR is calculated by using the RTDP methodology, which includes appropriate margin to DNB for all operating conditions sufficient to assure compliance with the DNBR criteria above.

The SAL, which is higher than the Design Limit DNBR, is conservatively utilized in the DNB safety analyses to provide DNBR margin to offset the effect of rod bow and any other DNBR penalties that may occur, and to provide flexibility in design and operation of the plant. To account for various penalties and potential operational issues, the plant-specific margins are retained between the Design Limit DNBR and the SAL DNBR.

2.8.3.2.3 Description of Analyses and Evaluations

For the SPU analysis, the design limit DNBR value for the RFA/RFA-2 fuel is [ ] ^{a,c} for typical and thimble cells. After accounting for the plant-specific margin, the SAL DNBR is [ ] ^{a,c} (typical/thimble). These SALs are employed in the DNB analyses.

With the SAL DNBR set, the core limits, axial offset limits, and dropped rod limits are generated. Based on these limits, the maximum $F^N{}_{\Delta H}$ limit that can be supported is [ ] ^{a,c}. This limit incorporates all applicable uncertainties, including a measurement uncertainty of [ ] ^{a,c} percent (Reference 5), and is adjusted for power level using the following equation:

$$F^N{}_{\Delta H} = 1.65 \times [1 + 0.3(1\text{-}P)]$$

where P is the fraction of full power.

Rod bow can occur between mid-grids, reducing the spacing between adjacent fuel rods and reducing the margin to DNB. Rod bow must be accounted for in the DNBR safety analysis of Condition I and Condition II events. Westinghouse has conducted tests to determine the impact of rod bow on DNB performance, the testing and subsequent analyses were documented in Reference 6.

Currently, the maximum rod bow penalty for the RFA/RFA-2 fuel assembly is [ ] ^{a,c} at an assembly average burnup of 24,000 MWD/MTU (References 6 and 7). No additional rod bow penalty is required for burnups greater than 24,000 MWD/MTU since credit is taken for the effect of $F^N{}_{\Delta H}$ burndown due to the decrease in fissionable isotopes and the buildup of fission products (Reference 8).

Two different bypass flow rates are used in the thermal-hydraulic design analysis. The thermal design bypass flow (TDBF) is the conservatively high core bypass flow used with the thermal design flow (TDF) in power capability analyses that use standard (non-statistical) methods, and is also used to calculate fuel assembly pressure drops. The best estimate bypass flow (BEBF) is the core bypass flow that would be expected using nominal values for dimensions and operating parameters that affect bypass flow without applying uncertainty factors. The BEBF is used in conjunction with the vessel minimum measured flow (MMF) for power capability analyses using the RTDP (statistical) design procedure. The BEBF is also used to calculate fuel assembly lift forces. The TDBF limit is 8.6 percent and the BEBF limit is [ ] ^{a,c} percent based on thimble plug removal. The TDBF limit is 6.6 percent and the BEBF limit is [ ] ^{a,c} percent with thimble plugs inserted. The DNB analysis is based on the assumption of thimble plugs removed which bounds thimble plugs inserted since the increased cooling flow gives a DNB benefit. A [ ] ^{a,c} percent value for BEBF was used directly in the analysis. The limit was later revised to [ ] ^{a,c}. DNBR margin was used to cover this increase.

Fuel temperatures and associated rod internal pressures have been generated using the NRC-approved PAD code (Reference 9) for the RFA/RFA-2 fuel. The maximum fuel rod average and surface temperatures are needed for the accident analyses. In addition, minimum fuel average and fuel surface temperatures are required by Non-LOCA Analysis. Fuel centerline temperatures were also generated. These will be used for future verification, during reload design validation, to ensure that fuel melt will not occur.

In addition to the fuel temperatures and pressures, the core stored energy has been determined for use in containment analysis (refer to Section 2.6). Core stored energy is defined as the amount of energy in the fuel rods in the core above the local coolant temperature. The local core stored energy is normalized to the local linear power level. A value of [ ] ^{a,c} full power seconds has been determined.

Figure 2.8.3-1 provides representative data for the maximum and minimum fuel average temperatures. Figure 2.8.3-2 provides the fuel surface temperatures corresponding to the maximum and minimum fuel average temperatures in Figure 2.8.3-1. Figure 2.8.3-3 provides the maximum and minimum fuel centerline temperatures. The maximum kW/ft limit for fuel melt is [ ] ^{a,c}.

Fuel rod internal pressure is important in assessing the degree of burst and blockage which may occur after a loss-of-coolant accident. Pressures were computed with the PAD code (Reference 9). Fuel parameters for reload fuel are evaluated to confirm that the pressures used in the reference analyses remain applicable to the reload.

2.8.3.2.3.1 Loss of Flow

This section supplements the methodology discussed in Section 2.8.5.2.3.1.

The DNB analysis of the loss-of-flow accident was performed for SPU conditions. Several cases, including partial loss of flow (PLOF), complete loss of flow (CLOF), CLOF-under frequency (CLOF-UF) and LOF P-8 statepoints were analyzed to ensure the limiting scenario was identified. The effect of updated fuel temperature was utilized in the analysis of this event (Section 2.8.3.2.3). The minimum DNBRs calculated for these cases were greater than the safety analysis DNBR limit, thereby demonstrating compliance to the DNB design criterion for this event.

2.8.3.2.3.2 Locked Rotor

This section supplements the methodology discussed in Section 2.8.5.2.3.1.

The analysis of the locked rotor accident was performed for SPU conditions. The locked rotor accident is classified as an ANS Condition IV event. To estimate the radiation release possible as a consequence of the accident, DNB calculations were performed to quantify the inventory of rods that would experience DNB and be conservatively presumed to fail. For MPS3, the analysis indicates that there would be [ ] ^{a,c} percent rods in DNB due to the locked rotor accident. The radiological consequences analysis conservatively assumed 7 percent of the fuel rods as failed rods and showed that the site dose limits were met.

The Locked Rotor Peak Clad Temperature (PCT) was calculated with the VIPRE-01 code using STDP methodology. The following assumptions were used:

- DNB is assumed to occur at the beginning of the transient

- The Bishop-Sandberg-Tong film boiling heat transfer coefficient was used (Reference 12)
- The fuel-clad gap heat transfer coefficient is assumed to increase to 10000 Btu/hr-ft^2 at the beginning of the transient
- The Baker-Just correlation (Reference 13) was used to predict the heat addition due to the zirconium-water reaction.

The results showed that the PCT limit of 2700°F was met with a large margin.

2.8.3.2.3.3 RCCA Drop/Misoperation

This section supplements the methodology discussion of Section 2.8.5.4.3 for this non-LOCA event.

The NRC-approved Westinghouse analysis methods in Reference 10 were used for analyzing the RCCA drop event. The Dropped Rod Limit Lines (DRLL) defines DNB-based limits on peaking factors as functions of core inlet temperature, core power and pressure. Based on the DRLL and transient statepoints covering a range of reactivity insertion mechanisms, nuclear design calculations determined pre-drop $F_{\Delta H}$ values corresponding to the post-drop peaking factors at the SAL DNBR. The maximum pre-drop $F_{\Delta H}$ for each reload is specified in the COLR. The cycle-specific RCCA drop analysis confirms that all allowed pre-drop $F_{\Delta H}$ values do not violate the COLR limit, and the DNB design basis is met for power uprate. In addition, the maximum linear heat rate from the RCCA drop analysis is lower than the fuel centerline melt limit. Therefore, the peak fuel centerline melt temperature criterion is also met for this event.

2.8.3.2.3.4 Uncontrolled Rod Cluster Control Assembly Withdrawal from Subcritical

The analysis for the Uncontrolled Rod Cluster Control Assembly Withdrawal from Subcritical (RWFS) is based on the STDP methodology since the event was initiated from Hot Zero Power (HZP) conditions. The W-3 correlation was used below the first mixing vane grid and the WRB-2 correlation was used above the first mixing vane grid. The minimum DNBRs were greater than the limit of 1.30 for the W-3 correlation and 1.17 for the WRB-2 correlation. Additional information is contained in Section 2.8.5.4.1.

2.8.3.2.3.5 Steam Line Break Accident

The event description is provided in Section 2.8.5.1.2. Cases were analyzed for both HZP and Hot Full Power (HFP) preconditions. For each of these cases, an appropriate methodology was applied. For the HFP cases, the RTDP methodology was used. For acceptability, calculated DNBRs must be above the RTDP design limit DNBR values. For the HZP cases, the RTDP methodology was not appropriate, so the mechanistic STDP was applied. For the STDP application, the DNBR limit was the approved W-3 correlation DNBR limit of 1.45, which has been acknowledged by the NRC as sufficiently high to ensure DNB criterion acceptance. Both HFP and HZP SLB are typically reanalyzed for each reload. Limiting statepoints are used for confirmation of the DNBR criteria. The calculated minimum DNBR for HFP and HZP cases were above the DNBR limits for the SPU analysis.

2.8.3.2.4 Impact on Renewed Plant Operating License Evaluations and License Renewal Program

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the Fuels Thermal Hydraulic Design analysis. As stated in Section 2.8.3.1, the evaluation of core thermal and hydraulic design was not within the scope of License Renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.3.2.5 Results

Core thermal-hydraulic analyses were performed in support of MPS3 operation at the SPU core power level of 3650 MWt. Table 2.8.3-5 summarizes the available DNBR margin for MPS3. It should be noted that the DNBR margin summaries are cycle-dependent and may vary from cycle-to-cycle in future reload designs. The continued satisfaction of the DNBR criterion for reload cycles is confirmed via the approved reload methodology of WCAP-9273-NP-A (Reference 11).

For the SPU analysis, the design limit DNBR value for the RFA/RFA-2 fuel is [ ] ^{a,c} for typical and thimble cells. After accounting for the plant-specific margin, the SAL DNBR is [ ]^{a,c}. These SALs are employed in the DNB analyses.

With the SAL DNBR set, the core limits, axial offset limits, and dropped rod limits are generated. Based on these limits, the maximum $F^N_{\Delta H}$ limit that can be supported is 1.65. This limit incorporates all applicable uncertainties, including a measurement uncertainty of [ ] ^{a,c}, and is adjusted for power level using the following equation:

$$F^N_{\Delta H} = 1.65 \times [1 + 0.3(1-P)]$$

where P is the fraction of full power.

The maximum rod bow penalty for the RFA/RFA-2 fuel assembly is [ ]^{a,c} at an assembly average burnup of 24,000 MWD/MTU. No additional rod bow penalty is required for burnups greater than 24,000 MWD/MTU since credit is taken for the effect of $F^N_{\Delta H}$ burndown due to the decrease in fissionable isotopes and the buildup of fission products.

For the two different bypass flow rates that are used in the thermal-hydraulic design analysis, the TDBF limit is 8.6 percent and the BEBF limit is [ ] ^{a,c} based on thimble plug removal. With thimble plugs inserted, the TDBF limit is 6.6 percent and the BEBF limit is [ ] ^{a,c}.

For LOF studies, the minimum DNBRs calculated for PLOF, CLOF, CLOF-UF and LOF P-8 statepoints cases were greater than the safety analysis DNBR limit, thereby demonstrating compliance to the DNB design criterion for this event.

For Locked Rotor studies, the analysis indicates that there would be [ ] ^{a,c} percent rods in DNB due to the locked rotor accident. The radiological consequences analysis conservatively assumed 7 percent of the fuel rods as failed rods and showed that the site dose limits were met. The Locked Rotor Peak Clad Temperature (PCT) was calculated with the VIPRE-01 code using

STDP methodology. The results showed that the PCT limit of 2700°F was met with a large margin.

The cycle-specific RCCA drop analysis confirms that all allowed pre-drop F_H values do not violate the COLR limit, and the DNB design basis is met for power uprate. In addition, the maximum linear heat rate from the RCCA drop analysis is lower than the fuel centerline melt limit. Therefore, the peak fuel centerline melt temperature criterion is also met for this event.

The analysis for the Uncontrolled Rod Cluster Control Assembly Withdrawal from Subcritical (RWFS) showed that the minimum DNBRs were greater than the limit of 1.30 for the W-3 correlation and 1.17 for the WRB-2 correlation.

The analyses for SLB showed the calculated minimum DNBR for HFP and HZP cases were above the DNBR limits for the SPU analysis.

The total DNBR penalty is [ ]^{a,c}. The available DNBR margin is [ ]^{a,c}.

The SPU analysis demonstrates that the combined DNBR margin gain is enough to accommodate the SPU to 3650 MWt core power.

The effects of the proposed SPU on the hydraulic loads on the core are addressed in Section 2.8.1, Fuel System Design. The effects of the proposed SPU on the hydraulic loads on the RCS components are addressed in Section 2.2.2.3, Reactor Vessel and Supports and Core Supports.

2.8.3.3 Conclusion

DNC has reviewed the analyses related to the effects of the proposed SPU on the thermal and hydraulic design of the core and the RCS. DNC concludes that the analyses have adequately accounted for the effects of the proposed SPU on the thermal and hydraulic design and demonstrated that the design 1) has been accomplished using acceptable analytical methods, 2) is equivalent to the proven designs, 3) provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs, and 4) is not susceptible to thermal-hydraulic instability. DNC further concludes that the analyses have adequately accounted for the effects of the proposed SPU on the hydraulic loads on the core and RCS components. Based on this, DNC concludes that the thermal and hydraulic design will continue to meet the requirements of GDCs -10 and -12 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to thermal and hydraulic design.

2.8.3.4 References

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7. Letter from Rahe, E. P., Jr. (Westinghouse) to Miller, J. R. (NRC), "Partial Response to Request Number 1 for Additional Information on WCAP-8691, Revision 1," NS-EPR-2515, October 9, 1981; and Letter from Rahe, E. P., Jr. (Westinghouse) to Miller, J. R. (NRC), "Remaining Response to Request Number 1 for Additional Information on WCAP-8691, Revision 1," NS-EPR-2572, March 16, 1982.

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13. L. Baker, Jr., L.C. Just, "Studies of Metal-Water Reactors at High Temperature," ANL-6548, Argonne National Laboratories, May 1962.

Table 2.8.3-1
MPS3 Thermal-Hydraulic Design Parameter Comparisons

Thermal-Hydraulic Design Parameters(1)	Current Design Value	SPU Analysis Value
Reactor Core Heat Output, MWt(2)	3411	3650
Reactor Core Heat Output, 10^6 BTU/Hr(2)	11639	12454
Heat Generated in Fuel,%	97.4	97.4
Pressurizer Pressure, Nominal, psia	2250	2250
Radial Power Distribution(3)	1.70[1+0.3(1-P)]	1.65[1+0.3(1-P)]
HFP Nominal Coolant Conditions		
Vessel Thermal Design Flow Rate (including bypass) (5) 10^6 lbm/hr GPM	 135.4 363,200	 135.3 363,200
Core Flow Rate (excluding Bypass based on TDF) 10^6 lbm/hr GPM	123.8 331,965	123.7 331,965
Core Flow Area, ft^2	51.1	51.1
Core Inlet Mass Velocity (based on TDF), 10^6 lbm/hr-ft^2	2.42	2.42
Nominal Vessel/Core Inlet Temperature, °F	555.9	556.4
Vessel Average Temperature, °F	587.1	589.5
Core Average Temperature, °F	591.6	594.5
Vessel Outlet Temperature, °F	618.3	622.6
Core Outlet Temperature, °F	623.5	628.0
Average Temperature Rise in Vessel, °F	62.4	66.2
Average Temperature Rise in Core, °F	67.6	71.6
Heat Transfer		
Active Heat Transfer Surface Area, ft^2	59,742	59,742
Average Heat Flux, BTU/hr-ft^2	189,800	203,100
Average Linear Power, kW/ft	5.445	5.827

Table 2.8.3-1
MPS3 Thermal-Hydraulic Design Parameter Comparisons

Thermal-Hydraulic Design Parameters(1)	Current Design Value	SPU Analysis Value
Peak Linear Power for Normal Operation(4)kW/ft	14.16	15.15
Peak Linear Power for Prevention of Centerline Melt, kW/ft	22.4	22.6
Pressure Drop Across Core(6), psi	22.5	22.8

Notes:
1. All values correspond to a full core of RFA/RFA-2 fuel.
2. The proposed power level of 3650 MWt has been used for all thermal-hydraulic design analyses.
3. P = Thermal Power/Rated Thermal Power
4. Based on maximum F_Q of 2.6.
5. Based on thimble plugs removed, which bounds thimble plug insertion for DNBR analyses.
6. The pressure drops across core as in FSAR Table 4.4-1 are calculated using Thermal Design Flow of 363,200 gpm.

Table 2.8.3-2
Limiting Parameter Direction for DNB

Parameter	**Limiting Direction for DNB**
$F_{N\,\Delta H}$, nuclear enthalpy rise hot-channel factor	maximum
Heat generated in fuel (%)	maximum
Reactor core heat output (MWt)	maximum
Average heat flux (BTU/hr-ft^2)	maximum
Nominal vessel/core inlet temperature (°F)	maximum
Core pressure (psia)	minimum
Pressurizer pressure (psia)	minimum
Thermal design flow for non-RTDP analyses (gpm)	minimum
Minimum measured flow for RTDP analyses (gpm)	minimum

Table 2.8.3-3
Peaking Factor Uncertainties

$F_H = F^N_{\Delta H} \times F^E_{\Delta H}$		
where,	$F^N_{\Delta H}$	Nuclear Enthalpy Rise Hot Channel Factor – The ratio of the relative power of the hot rod, which is one of the rods in the hot channel, to the average rod power. The normal operation value of this is given in the Core Operating Limit Report (COLR).
	$F^E_{\Delta H}$	Engineering Enthalpy Rise Hot Channel Factor – The nominal enthalpy rise in an isolated hot channel can be calculated by dividing the nominal power into this channel by the core average inlet flow per channel. The engineering enthalpy rise hot channel factor accounts for the effects of flow conditions and fabrication tolerances. It can be written symbolically as:
$F^E_{\Delta H} = f\,(F^E_{\Delta H,1}, F^E_{\Delta H,2}, F^E_{\Delta H\ \text{inlet maldist}}, F^E_{\Delta H\ \text{redist}}, F^E_{\Delta H\ \text{mixing}})$		
where,	$F^E_{\Delta H,1}$	accounts for rod-to-rod variations in fuel enrichment and weight
	$F^E_{\Delta H,2}$	accounts for variations in fuel rod outer diameter, rod pitch, and bowing
	$F^E_{\Delta H\ \text{inlet maldist}}$	accounts for the non-uniform flow distribution at the core inlet
	$F^E_{\Delta H\ \text{redist}}$	accounts for flow redistribution between adjacent channels due to the different thermal-hydraulic conditions between channels
	$F^E_{\Delta H\ \text{mixing}}$	accounts for thermal diffusion energy exchange between adjacent channels caused by both natural turbulence and forced turbulence due to the mixing vane grids
The value of these factors and the way in which they are combined depends upon the design methodology used, that is, STDP or RTDP. Note that no actual combined effect value is calculated for $F^E_{\Delta H}$. These factors are accounted for by using the VIPRE-01 code.		

Table 2.8.3-4
RTDP Uncertainties and Biases

Parameter	Uncertainties[1] and biases Used in SPU Safety Analysis
Power	[ ] a,c
Reactor Coolant System Flow	[ ] a,c
Pressure	[ ] a,c
Inlet Temperature	[ ] a,c
Note 1: The uncertainties used in the SPU safety analysis are bounding values	

Table 2.8.3-5
DNBR Margin Summary[1]

DNB Correlation		- WRB-2M
DNBR Correlation Limit		- 1.14
DNBR Design Limit	(TYP/THM)[2]	- [ ] a,c
DNBR SAL	(TYP/THM)	- [ ] a,c
DNBR Retained Margin[3]	(TYP/THM)	- [ ] a,c
Rod Bow DNBR Penalty[4]	(TYP/THM)	- [ ] a,c
Condition II Power Shape Penalty	(TYP/THM)	- [ ] a,c
RWAP Penalty[5]	(TYP/THM)	- [ ] a,c
Power Bias	(TYP/THM)	- [ ] a,c
Reactor Coolant Flow Bias	(TYP/THM)	- [ ] a,c
Excess BEBF	(TYP/THM)	- [ ] a,c
Pressure Bias	(TYP/THM)	- [ ] a,c
Temperature Bias	(TYP/THM)	- [ ] a,c
Total Penalty[6]	(TYP/THM)	- [ ] a,c
Available DNBR Margin[7]	(TYP/THM)	- [ ] a,c

Notes:

1. The values below correspond to RTDP. HZP SLB and RWFS are based on STDP. The DNBR limit for HZP SLB is [ ]. The minimum DNBR for SPU analysis was above this limit. The HZP SLB is normally analyzed each cycle.
   The DNBR limits for RWFS are 1.30 with W-3 correlation below the first mixing vane grid and 1.17 above this grid. The minimum DNBRs were above these limits for SPU analysis.
2. TYP = Typical Cell.
   THM = Thimble Cell.
3. DNBR margin is the difference between the SAL and the design limit DNBRs.
4. The rod bow penalty is [ ] a,c.
5. RWAP = Rod Withdrawn at Power.
6. Total penalty is [ ] a,c for the mixing vane grid span.
7. Available margin is [ ] a,c for IFM span.

Figure 2.8.3-1 Fuel Average Temperatures

a,c

Figure 2.8.3-2 Fuel Surface Temperatures

a,c

Figure 2.8.3-3 Fuel Centerline Temperatures

a,c

2.8.4 Emergency Systems

2.8.4.1 Functional Design of the Control Rod Drive System (CRDS)

2.8.4.1.1 Regulatory Evaluation

The DNC review covered the functional performance of the CRDS to confirm that the system can effect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CRDS cooling system to ensure that it will continue to meet its design requirements.

The acceptance criteria are based on:

- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents
- GDC-23, insofar as it requires that the protection system be designed to fail into a safe state
- GDC-25, insofar as it requires that the protection system be designed to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded for any single malfunction of the reactivity control systems
- GDC-26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes
- GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained
- GDC-28, insofar as it requires that the reactivity control systems be designed to ensure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core
- GDC-29, insofar as it requires that the protection and reactivity control systems be designed to ensure an extremely high probability of accomplishing their safety functions in event of AOOs

Specific review criteria are contained in the SRP, Section 4.6, Rev. 1 and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), Section 4.6, Rev. 1.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to:

- GDC-4, Environmental and Missile Design Bases, is described in FSAR Section 3.1.2.4.

  SSCs important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

  SSCs important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in the FSAR, Section 3.2.5.

- GDC-23, Protection System Failure Modes, is described in FSAR Section 3.1.2.23. The protection system is designed with due consideration of the most probable failure modes of the components under various perturbations of the environment and energy sources. FSAR Sections 7.2 and 7.3 discuss this protection system.

- GDC-25, Protections System Requirements for Reactivity Control Malfunctions, is described in FSAR Section 3.1.2.25.

  The protection system is designed to limit reactivity transients so that fuel design limits are not exceeded. Reactor shutdown by full-length rod insertion is completely independent of the normal control function, since the trip breakers interrupt power to the rod mechanisms regardless of existing control signals. Thus, in the postulated accidental withdrawal (assumed to be initiated by a control malfunction), flux, temperature, pressure, level and flow signals would be generated independently. Any of these signals (trip demands) would operate the breakers to trip the reactor.

  FSAR Chapter 15 discusses analyses of the effects of possible malfunctions. These analyses show that for postulated dilution during refueling, startup, or manual or automatic operation at power, the operator has ample time to determine the cause of the dilution, terminate the source of the dilution, and initiate boron before the shutdown margin is lost. The analyses show that acceptable fuel damage limits are not exceeded even in the event of a single malfunction of either system.

- GDC-26, Reactivity Control System Redundancy and Capability, is described in FSAR Section 3.1.2.26.

  Two reactivity control systems are provided. They are the RCCAs and chemical shim (boric acid). The RCCAs are inserted into the core by the force of gravity.

During operation the shutdown rod banks are fully withdrawn. The rod control system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and AOOs, thereby ensuring that specific fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses, and the most reactive rod cluster is assumed to be in the fully withdrawn position.

FSAR Chapter 4 presents details of the construction for the RCCAs. FSAR Chapter 7 discusses their operation. FSAR Chapter 15 includes performance analyses under accident conditions.

- GDC-27, Combined Reactivity Control Systems Capability, is described in FSAR Section 3.1.2.27.

  MPS3 is provided with a means of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. FSAR Chapters 4 and 9 discuss these means in detail. Combined use of the rod cluster control system and the chemical shim control system permits the necessary shutdown margin to be maintained during long term xenon decay and plant cooldown. The single highest worth control cluster is assumed to be stuck full-out upon trip for this determination. FSAR Chapter 15 describes accident assumptions in detail.

- GDC-28, Reactivity Limits, is described in FSAR Section 3.1.2.28.

  The maximum reactivity worth of control rods and the maximum rate of reactivity insertion employing control rods are limited to values that prevent rupture of the RCS boundary or disruption of the core or vessel internals to a degree that could impair the effectiveness of emergency core cooling.

  The maximum positive reactivity insertion rates for the withdrawal of RCCAs and the dilution of the boric acid in the RCS are limited by the physical design characteristics of the RCCAs and of the CVCS. TS on shutdown margin and on RCCA insertion limits and bank overlaps as functions of power provide additional assurance that the consequences of the postulated accidents are no more severe than those presented in the analyses of FSAR Chapter 15. Reactivity insertion rates, dilution, and withdrawal limits are also discussed in FSAR Section 4.3. The capability of the CVCS to avoid an inadvertent excessive rate of boron dilution is discussed in FSAR Section 15.

- GDC-29, Protection Against Anticipated Operational Occurrences, is described in FSAR Section 3.1.2.29.

  The protection and reactivity control systems are designed to assure an extremely high probability of accomplishing their safety functions in any operational occurrences. Equipment used in these systems is designed, constructed, operated, and maintained with a high level of reliability. FSAR Chapter 7 provides details of system design.

As stated in FSAR Section 3.9N.4.1, the CRDMs are located on the dome of the RV head. They are coupled to rod cluster control assemblies (RCCAs) which have neutron absorber material over the entire length of the control rods. The primary function of the CRDM is to insert, withdraw or hold stationary, RCCAs within the core to control core average temperature and to shutdown the reactor. The CRDM is a magnetically-operated jack. A magnetic jack is an arrangement of three electromagnets which are energized in a controlled sequence by a power cycler to insert or withdraw RCCAs in the reactor core in discrete steps. Rapid insertion of the RCCAs occurs when electric power is interrupted. The CRDM can be tripped during any part of the power cycler sequence if electric power to the coils is interrupted, thereby releasing the drive rod assembly and inserting the RCCA.

As stated in FSAR Section 4.6, the CRDS includes the CRDMs (discussed in FSAR Section 3.9N4.1), the Rod Control system (discussed in FSAR Section 7.7.1.2) and the Reactor Trip Switchgear (discussed in FSAR Section 7.2.1.1).

FSAR Section 4.6.2 also states in part that the CRDS has been analyzed in detail in a FMEA in WCAP-8976. Changes to the results of this analysis to account for timing changes to the Rod Control System are described in WCAP-13864. These studies and the analyses presented in FSAR Section 15.0 demonstrate that the CRDS performs its intended safety function, reactor trip, by putting the reactor in a subcritical condition when a safety system setting is approached, with any assumed credible failure of a single active component. The essential elements of the CRDS are isolated from the nonessential portions of the CRDS (the Rod Control System).

The design of the CRDM is such that failure of the CRDM cooling system will, in the worst case, result in an individual control rod drop or a full reactor trip.

Other FSAR sections which address the design features and function of the CRDM and chemical reactivity control systems are as follows:

- FSAR Section 7.2, Reactor Trip System, which provides a description of the reactor trip system interface with the rod control system.
- FSAR Section 7.7.1.2, Rod Control System, which provides a description of the operation of the rod control system.
- FSAR Section 7.7.1.3.2, Rod Position Monitoring of Full Length Rods, which provides a description of the Digital Rod Position Indication System and the Demand Position System.
- FSAR Section 9.4.7.4, CRDM Ventilation and Cooling Subsection, which describes the design of the CRDM cooling system.
- FSAR Section 15.4, Reactivity and Power Distribution Anomalies, describe the transient and accident analyses associated with the malfunctions of the rod control and chemical and volume control systems.

The CRD system and the CRDM cooling system (passive components) were evaluated for continued acceptability to support license renewal. NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3*,"* dated August 1, 2005, documents the results of that review. NUREG-1838, Section 2.3B.3.26, is applicable to the CRD Ventilation and Cooling System. NUREG-1838, Section 2.3B.1.1, is applicable to the CRDM.

2.8.4.1.2 Technical Evaluation

2.8.4.1.2.1 Introduction

The potential impact of the SPU on the CRDS results from the temperature effects associated with increasing reactor core thermal power from 3411 MWt to 3650 MWt.

CRDMs use electro-magnetic coils to position the rod cluster control assemblies (RCCAs) within the reactor core. The insulation and potting materials used in the construction of the coils are subject to thermal aging. In order to reduce the thermal aging, CRDM cooling systems were designed to remove heat supplied by conduction and convection from the reactor head and reactor coolant.

2.8.4.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The temperature of the MPS3 reactor vessel head is the same as the reactor vessel inlet temperature. Section 1.1, Table 1-1 indicates that the SPU full power reactor vessel inlet temperature increases from 555.9°F to a maximum of 556.4°F. The zero load temperature of 557°F is, however, the maximum reactor vessel inlet temperature for both the current condition and all cases evaluated for the 7 percent SPU.

The specific CRDM acceptance criteria are to demonstrate that the temperatures associated with the SPU on the components and coils of the CRDM remain acceptable.

As a result of the SPU, there are no physical changes required to the control rod drive system, operating coil stacks, power supplies, solid state electronic control cabinets, or the control rod drive cooling system.

2.8.4.1.2.3 Description of Analyses and Evaluations

Transient and accident analyses for the events listed in the FSAR Chapter 15 were performed for the SPU conditions listed in Section 1.1, Nuclear Steam Supply System Parameters, Table 1-1. These analyses are described in Section 2.8.5, Accident and Transient Analyses. All events associated with the control rod drive system provided acceptable results and maintained DNB, the reactor coolant system pressure, and main steam system pressure within the acceptable limits.

Analyses and evaluations of the impact of the SPU on the structural integrity of the control rod drive system during normal, transient, and accident conditions were also performed using the SPU conditions listed in Section 1.1, Table 1-1. These analyses and evaluations are discussed in Section 2.2.2.4, Control Rod Drive Mechanism. The results of the analyses and evaluations determined the structural integrity of the control rod drive system remained within acceptable limits at SPU conditions.

With respect to CRDM cooling, as indicated above, the temperature of the MPS3 reactor vessel head is the same as the reactor vessel inlet temperature. Since the primary source of heat to the CRDM cooling system is conduction and convection from the reactor vessel head, the temperature of the CRDMs and amount of heat rejected to the containment building are also a function of the reactor vessel inlet temperature. To evaluate the effects of the SPU on the CRDM cooling system, the maximum current condition reactor inlet temperature is compared to the maximum reactor inlet temperature following implementation of the SPU. Section 1.1, Table 1-1 indicates that the zero load temperature of 557°F is the maximum reactor vessel inlet temperature for both the current condition and all cases evaluated for the 7 percent SPU. Given that the maximum reactor vessel head remains unchanged for the SPU, the performance of the CRDM cooling system and maximum heat load on containment from this system are not affected by the SPU.

The changes to the CRDM operating temperatures as a result of the SPU are small, and therefore, have no effect upon CRDM functionality and operability.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The MPS3 SPU does not require any new components or introduce any new functions for existing control rod drive system components that would require revision of the license renewal system evaluation boundaries. The operation of the control rod drive and control rod drive mechanism cooling systems at SPU conditions does not result in any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.8.4.1.2.4 Results

DNC has reviewed the functional design of the control rod drive system and the CRDM cooling system for the effects of the SPU. Accident and Transient Analyses described in Section 2.4.2, Plant Operability, and Section 2.8.5, Accident and Transient Analyses, have demonstrated that at SPU conditions the rod control system continues to satisfy the design basis for reactivity control and ensure specified acceptable fuel design limits are met for any single malfunction of the reactivity control systems.

The impact of the SPU on the structural integrity of the CRDMs is discussed in Section 2.2.2.4, Control Rod Drive Mechanism. No modifications have been made to the hardware, logic or operation of the system that affect the system's current ability to fail into a safe state. As discussed in Section 1.0, the auto rod withdrawal feature of the CRDS is being eliminated so any postulated accidental withdrawal would be initiated by an operator error. This change, however, does not impact the ability of the CRDS to fail into a safe state. The impact of the SPU on the Control Rod Drive Cooling System was evaluated and there is no impact to the cooling system.

2.8.4.1.3 Conclusion

DNC has reviewed the analyses related to the effects of the proposed SPU on the functional design of the CRDS. DNC concludes that the evaluation has adequately accounted for the effects of the proposed SPU on the system and demonstrated that the system's ability to effect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents will be maintained following the implementation of the proposed SPU. DNC further concludes that the evaluation has demonstrated that sufficient cooling exists to ensure the system's design bases will continue to be followed upon implementation of the proposed SPU. Based on this, DNC concludes that the CRDS and associated analyses will continue to meet the requirements of GDCs -4, -23, -25, -26, -27, -28, and -29 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the functional design of the CRDS.

2.8.4.2 Overpressure Protection During Power Operations

2.8.4.2.1 Regulatory Evaluation

Overpressure protection for the RCPB during power operation is provided by relief and safety valves and the RPS. The DNC review covered pressurizer relief and safety valves and the piping from these valves to the quench tank.

The acceptance criteria are based on:

- GDC-15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs
- GDC-31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a non-brittle manner and the probability of rapidly propagating fracture is minimized

Specific review criteria are contained in the SRP Section 5.2.2, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), Section 5.2.2, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to:

- GDC-15, Reactor Coolant System Design, is described in FSAR Section 3.1.2.15.

  The design pressure and temperature for each component in the reactor coolant and associated auxiliary, control and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

- GDC-31, Fracture Prevention of Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.31.

  Close control is maintained over material selection and fabrication for the RCS to assure that the boundary behaves in a non-brittle manner. The RCS materials exposed to the coolant are corrosion resistant stainless steel or Inconel. The nil ductility reference temperature of the RV structural steel is established by Charpy V-notch and drop weight tests, in accordance with 10 CFR 50, Appendix G.

FSAR Section 5.2.2 states that overpressure protection is provided for the RCS by the pressurizer safety valves. This protection is afforded for the following events:

- Loss of electrical load and/or turbine trip

- Uncontrolled rod withdrawal at power
- Loss of reactor coolant flow
- Loss of normal feedwater
- Loss of offsite power to the station auxiliaries

These events bound those credible events that could lead to overpressure of the RCS if adequate overpressure protection were not provided.

The sizing of the pressurizer safety valves is based on analysis of a complete loss of steam flow to the turbine with the reactor operating at 102 percent of engineered safeguards design power. In this analysis, feedwater flow is also assumed to be lost, and no credit is taken for operation of pressurizer power operated relief valves, pressurizer level control system, pressurizer spray system, rod control system, steam dump system, or steam line power operated relief valves. The reactor is maintained at full power (no credit for direct reactor trip on turbine trip), and steam relief through the steam generator safety valves is considered. The total pressurizer safety valve capacity is required to be at least as large as the maximum surge rate into the pressurizer during this transient.

This sizing procedure results in a pressurizer safety valve capacity well in excess of the capacity required to prevent exceeding 110 percent of system design pressure for the events listed in this section.

A description of the pressurizer safety valves, including a design basis discussion is provided in FSAR Section 5.4.13.

The MPS3 RCS and components, such as valves, were evaluated for continued acceptability to support plant license renewal. NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3," dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.3B.1.3 and 3.1B are applicable to the pressurizer safety valves.

2.8.4.2.2 Technical Evaluation

2.8.4.2.2.1 Introduction

The limiting credible event with respect to primary and secondary system overpressurization is the loss-of-external-electrical-load/turbine-trip (LOL/TT) event. This section briefly summarizes the LOL/TT analysis performed for MPS3 which demonstrates that the overpressure criteria continue to be met for the proposed SPU. Details of that analysis are given in Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum.

The technical evaluations of the RCS and components are described in Section 2.2.2, Pressure-Retaining Components and Component Supports. The technical evaluation of the Pressurizer safety valves is described in Section 2.8.7, NSSS/BOP Components. The technical evaluation of the piping from the safety valves to the PRT is described in Section 2.5.2, Pressurizer Relief Tank.

Note that overpressure protection during low temperature operation is discussed in Section 2.8.4.3, Overpressure Protection During Low Temperature Operation.

2.8.4.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The LOL/TT cases for maximizing the RCS and MSS peak pressures were analyzed using the standard thermal design procedure (STDP). Initial uncertainties on reactor coolant flow, temperature, and pressure were applied in the conservative direction to obtain the initial plant conditions for the transient. Further details of the input parameters and assumptions for the LOL/TT analyses at the proposed SPU conditions are discussed in Section 2.8.5.2.1.

For this event, primary and secondary system pressures must remain below 110 percent of their respective design pressures (an RCS pressure limit of 2750 psia and secondary side pressure limit of 1320 psia) at all times during the transient. Demonstrating that the primary and secondary pressure limits are met satisfies the requirements of GDC-15 and GDC-31.

2.8.4.2.2.3 Description of Analyses and Evaluations

For the LOL/TT event, the behavior of MPS3 was analyzed for a complete loss of steam load from full power without a direct reactor trip. A detailed analysis was performed, as described in Section 2.8.5.2.1, to determine the plant transient conditions following a total loss of load.

In addition, per the guidance in Note 4 of Matrix 8 of RS-001, an analysis was performed to determine the allowable power levels with inoperable main steam safety valves for Technical Specification 3.7.1.1. This Technical Specification allows MPS3 to operate with a reduced number of operable MSSVs at a reduced power level, as determined by resetting the power range high neutron flux setpoint. In order to preclude secondary side overpressurization in the event of a LOL/TT event, the maximum power level allowed for operation with inoperable MSSVs must be below the heat removing capability of the operable MSSVs. Table 3.7-1 of the Technical Specifications defines the power range high neutron flux setpoint corresponding to the one, two, or three inoperable MSSVs. The algorithm used for calculating the high neutron flux setpoints uses the nominal NSSS power rating of the plant, the minimum total steam flow rate capability of the operable MSSVs on any one steam generator at the highest MSSV opening pressure and the heat of vaporization at the highest MSSV opening pressure. The lowest flow available from the operable valves and the lowest heat of vaporization at the highest set pressure are used to provide the most conservative setpoint values. The calculation of the maximum allowable power range neutron flux high setpoints specified in Table 3.7-1 of the Technical Specifications also accounts for a 9 percent uncertainty in the reactor trip setpoint.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the analysis of Overpressure Protection During Power Operations. Transient analyses are not within the scope of license renewal. DNC has also evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the RCS and components, and Pressurizer safety valves. These evaluations are documented in Section 2.2.2, Pressure-Retaining Components and Component Supports and Section 2.8.7, NSSS/BOP Components, respectively. Therefore, there is no impact on the evaluations performed for License Renewal and they remain valid for the SPU conditions.

2.8.4.2.2.4 Results

The results of the LOL/TT analysis documented in Section 2.8.5.2.1 demonstrate that the primary and secondary pressure limits are met at the proposed SPU conditions. Specifically, the maximum pressure in the primary system is 2729.4 psia vs. a limit of 2750 psia and the maximum secondary system pressure is 1302.3 psia vs. a limit of 1320 psia. No changes were needed to the primary or secondary relief or safety valves in order to meet the applicable pressure limits.

Operation at the SPU conditions will have no impact on the reliability of the reactor protection system or the safety valves and thus conclusions of the Overpressure Protection Report referenced in the FSAR remain valid.

Table 2.8.4.2-1 provides the maximum allowable power range neutron flux high setpoints with inoperable MSSVs for the SPU along with the current Technical Specification Table 3.7-1 setpoints. Since more restrictive setpoints are required to prevent secondary side overpressurization with inoperable MSSVs for the proposed SPU, the Technical Specification Table 3.7-1 will be revised accordingly.

2.8.4.2.3 Conclusion

DNC has reviewed the analyses related to the effects of the proposed SPU on the overpressure protection capability of the plant during power operation. DNC concludes that the analyses have 1) adequately accounted for the effects of the proposed SPU on pressurization events and overpressure protection features, and 2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, DNC concludes that the overpressure protection features will continue to provide adequate protection to meet GDC-15 and GDC-31 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to overpressure protection during power operation.

Table 2.8.4.2-1
Maximum Allowable Power Range Neutron Flux High Setpoint with Inoperable MSSVs

Maximum Number of Inoperable Safety Valves on Any Operating SG	Proposed SPU Technical Specification Setpoint (% of RTP)	Current Technical Specification Setpoint (% of RTP)
1	60.1	65
2	42.8	46
3	25.5	28

2.8.4.3 Overpressure Protection During Low Temperature Operation

2.8.4.3.1 Regulatory Evaluation

Overpressure protection for the reactor coolant pressure boundary during low temperature operation of MPS3 is provided by pressure-relieving systems that function during the low temperature operation. DNC's review covered reactor coolant system relief valves with piping to the pressurizer relief tank, the charging and letdown system, and the residual heat removal system, which may be operating when the primary system is water solid. The acceptance criteria for this review are:

- GDC-15, insofar as it relates to the reactor coolant system and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences; and,
- GDC-31, insofar as it relates to the reactor coolant pressure boundary be designed with sufficient margin to assure that it behaves in a non-brittle manner and the probability of rapidly propagating fracture is minimized.

Specific Review criteria are contained in SRP Section 5.2.2 and guidance is provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with the NUREG-0800, Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, SRP Section 5.2.2, Rev. 1.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the GDC is discussed in the FSAR Sections 3.1.1 and 3.1.2.

- GDC-15, Reactor Coolant System Design, is described in FSAR Section 3.1.2.15.

  The design pressure and temperature for each component in the reactor coolant and associated auxiliary, control, and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

  Additionally, RCPB components achieve a large margin of safety by the use of proven ASME materials and design codes, use of proven fabrication techniques, nondestructive shop testing, and integrated hydrostatic testing of assembled components. FSAR Chapter 5 discusses the reactor coolant system design.

- GDC-31, Fracture Prevention of Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.31.

  Close control is maintained over material selection and fabrication for the RCS to assure that the boundary behaves in a non-brittle manner. The reactor coolant system materials, which are exposed to the coolant, are corrosion resistant stainless steel or Inconel. The NIL ductility reference temperature (RTNDT) of the reactor vessel structural steel is established by

Charpy V-notch and drop weight test in accordance with 10 CFR 50, Appendix G. The fabrication and quality control techniques used in the fabrication of the RCS are consistent with those used for the reactor vessel. Allowable pressure-temperature relationships for plant heatup and cooldown rates are calculated using methods derived from ASME code, Section III, Appendix G, Protection Against Non-ductile Failure. The approach specifies that allowed stress intensity factors for all vessel-operating conditions might not exceed the reference stress intensity factor for the metal temperature at any time. Operating specifications include conservative margins for predicted changes in the material reference temperature (RTNDT) due to irradiation.

The RCS pressure control during low temperature operation is described in FSAR Section 5.2.2.11. Administrative procedures are available to assist the operator in controlling RCS pressure during low temperature operation. However, to provide a backup to the operator and to minimize the frequency of RCS pressurization, an automatic system is provided to mitigate any inadvertent excursion.

The cold overpressure protection system (low temperature overpressure protection system) limits RCS pressure at low temperatures in order to prevent compromising the integrity of the RCPB or a violation of the isothermal beltline PT limits developed using the guidance of ASME Section XI, Appendix G, as modified by ASME Code Case N-640. The reactor vessel is the limiting RCPB component for demonstrating such protection.

MPS3 LCO 3.4.9.3 provides RCS overpressure protection by limiting mass input capability and requiring adequate pressure relief capacity. The mass input capability is limited by the requirement for all safety injection pumps and all but one charging pump to be incapable of injecting into RCS whenever an RCS cold leg is ≤ 226°F. The pressure relief capacity is provided by the requirement for: 1) two redundant relief valves (PORVs, RHR suction relief valves, or a combination) to be operable; or 2) the RCS depressurized and an RCS vent of sufficient size provided. One relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event. Two relief valves are required for redundancy. A PORV may only be utilized for low temperature overpressure protection when no more than one RCS loop is isolated from the reactor vessel.

The analyses of the low temperature overpressure protection mass and heat additions are performed at reactor shutdown and RCS cold conditions (i.e., whenever an RCS cold leg is ≤ 226°F). The following are examples of transients capable of overpressurizing the RCS: 1) Inadvertent safety injection (mass input transient); 2) Charging/letdown flow mismatch (mass input transient); 3) Inadvertent actuation of pressurizer heaters (heat input transient); 4) Loss of RHR cooling (heat input transient); or 5) RCP startup with temperature asymmetry within the RCS or between the RCS and steam generators (heat input transient).

The limiting mass addition transient that can occur during RCS low temperature operation is the injection of a charging pump at a run-out flow of 560 gpm with letdown isolated. The limiting heat addition transient analysis assumes a RCP startup with a 50°F mismatch between the RCS and the temperature of the hotter secondary side of the steam generators. Both heat addition and mass addition analyses take into account the single failure criteria and, therefore, only one relief valve is assumed to be available for pressure relief. These events have been evaluated considering the allowable isothermal beltline pressure/temperature limits. (FSAR Section 5.2.2.11.2)

The analyses show that the vessel is protected against non-ductile failure when the PORVs are set to open at the values established in the Technical Specifications within the tolerance allowed for the calibration accuracy. The curves are derived by analyses for both three and four RCS loops unisolated that model the performance of the PORV low temperature overpressure protection system, assuming the limiting mass and heat transients of one centrifugal charging pump injecting into the RCS, or the energy addition as a result of starting an RCP with temperature asymmetry between the RCS and the steam generators. These analyses consider pressure overshoot beyond the PORV opening setpoint resulting from signal processing and valve stroke times.

The RHR suction relief valves do not have variable pressure and temperature lift setpoints as do the PORVs. Analyses show that one RHR suction relief valve with a setpoint that complies with LCO 3.4.9.3 will pass flow greater than that required for the limiting low temperature overpressure transient while maintaining RCS pressure less than the isothermal PT limit curve. Assuming maximum relief flow requirements during the limiting cold overpressure event, an RHR suction relief valve will maintain RCS pressure to less than or equal to 110 percent of the nominal lift setpoint.

With the RCS depressurized, the analyses show that the vent size required by LCO 3.4.9.3 is capable of mitigating the limiting cold overpressure transient. The capacity of this vent size is greater than the flow of the limiting transient, while maintaining RCS pressure less than the maximum pressure on the isothermal P/T limit curve.

Each time the Technical Specification P/T curves are revised, the low temperature overpressure protection requirements are re-evaluated to ensure the functional requirements continue to be met by the RCS relief valve method or the depressurized and vented RCS condition.

On June 25, 1990, the NRC issued GL 90-06, Resolution of Generic Issue (GI) 70, ‘Power-Operated Relief Valve and Block Valve Reliability,’ and Generic Issue 94, ‘Additional Low-Temperature Overpressure Protection for Light-Water Reactors.’

- GI 70 involves the evaluation of the reliability of the PORVs and block valves and their significance in PWR plants. The GL also discussed how PORVs are increasingly being relied on to perform safety-related functions and the corresponding need to improve the reliability of both PORVs and their associated block valves. Proposed NRC positions and improvements to the plants technical specifications were delineated to be implemented at all affected facilities (PWRs).
- GI 94 addresses concerns with the implementation of the requirements set forth in the resolution of USI A-26, “Reactor Vessel Pressure Transient Protection (Overpressure Protection).” The GL discussed the continuing occurrence of overpressure events and the need to further restrict the allowed outage time for a low-temperature overpressure protection channel operating in Modes 4, 5, and 6. This issue is only applicable to Westinghouse and Combustion Engineering facilities.

On March 19, 1993, a license amendment request was submitted to the NRC to change the Technical Specifications to address GI 94 and GI 70. On July 12, 1993, and December 16, 1993, the NRC approved the requests, and issued license amendments that closed GI 94 and GI 70, respectively.

The MPS3 low temperature overpressure protection system was evaluated for the continued acceptability for the purpose of plant license renewal. NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3," dated August 1, 2005, documents the results of that review. The overpressure protection system components are addressed in Sections 2.3B.1.3 and 3.1B of NUREG-1838.

2.8.4.3.2 Technical Evaluation

2.8.4.3.2.1 Initial Parameters

An evaluation has been performed to confirm that SPU has no impact on input parameters used in the cold overpressurization analyses. These include the following:

- Charging capacity
- RCS flow rate
- PORV overshoot
- RCS pressure and temperature uncertainties.

The only significant change due to SPU is a small increase in decay heat.

2.8.4.3.2.2 Mass Addition Transient

The limiting mass addition transient is the inadvertent startup of a charging pump. The SPU has no impact on the capacity of the charging pump. Thus, there is no impact on the current bounding analysis for the mass addition transient.

2.8.4.3.2.3 Heat Addition Transient

The limiting mass addition transient is the inadvertent startup of a RCP with the steam generator 50°F hotter than the RCS. The sudden increase in flow results in a high primary-to-secondary heat transfer rate. This is the dominant heat addition mechanism and is independent of any changes to SPU, including decay heat. Since the change in decay heat is small and the primary-to-secondary heat transfer is dominant, the inadvertent startup of a RCP is unaffected. Thus, the SPU has no impact on the current bounding analysis for the heat addition transient.

2.8.4.3.2.4 RHR Relief Valve Capability to Mitigate a Cold Overpressurization Event

Since the current analyses for the limiting mass addition and heat addition transients remain bounding, the current analysis demonstrating the capability of the RHR relief valves to mitigate a cold overpressurization event remains valid. Thus, the SPU has no impact on the capability of the RHR relief valves to mitigate a cold overpressurization event.

2.8.4.3.2.5 Pressure-Temperature Curves

No change is necessary to the Pressure-Temperature curves applicable to 32 Effective Full Power Years presented in Figures 3.4-2 and 3.4-3 of the Technical Specifications. A more detailed discussion of the pressure-temperature curves is presented in Section 2.1.2.

2.8.4.3.2.6 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The SPU does not have an impact on the limiting mass addition or heat addition transients regarding low temperature overpressure events. The analyses presented in FSAR Section 5.2.2.11 remain valid. Thus, the SPU conditions do not require any new components, or functions for existing components that would change the license renewal system evaluation boundaries. In addition, no new or previously unevaluated materials are added to the plant systems. Based on the SPU evaluation, no new aging effects requiring management are identified for the period of extended operation of the plant.

2.8.4.3.2.7 Results

The SPU does not impact the current analysis or results for the limiting events for cold overpressurization mitigation. While there is a small increase in decay heat, the increase does not affect the limiting heat addition event of an inadvertent RCP startup. The inadvertent RCP startup continues to bound the loss of RHR event. Since there is no change in the PT limit curves and the current analysis remains bounding, no change in the cold overpressure protection system setpoints are needed to assure that the requirements of 10 CFR 50, Appendix G, are met at SPU conditions.

2.8.4.3.3 Conclusion

DNC has reviewed the analyses related to the effects of the proposed SPU on the overpressure protection capability of the plant during low temperature operation. DNC concludes that: 1) the analyses adequately accounted for the effects of the proposed SPU on pressurization events and overpressure protection features; and 2) the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded.

Based on this, DNC concludes that the low temperature overpressure protection features will continue to provide adequate protection to meet the MPS3 current licensing basis requirements with respect to GDC-15 and GDC-31 following implementation of the SPU. Therefore, DNC finds the proposed SPU acceptable with respect to overpressure protection during low temperature operation.

2.8.4.4 Residual Heat Removal System

2.8.4.4.1 Regulatory Evaluation

The RHR system is used to cooldown the RCS following shutdown. The RHR system is typically a low pressure system which takes over the shutdown cooling function when the RCS temperature is reduced. The DNC review covered the effect of the proposed SPU on the functional capability of the RHR system to cool the RCS following shutdown and provide decay heat removal.

The acceptance criteria are based on:

- GDC-4, insofar as it requires that SSCs important to safety be protected against dynamic effects,
- GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions, and
- GDC-34, which specifies requirements for an RHR system.

Specific review criteria are contained in SRP Section 5.4.7 and other guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800 Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, April 1984, SRP Section 5.4.7, Rev. 3. As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to conformance to the following:

- GDC-4 is described in FSAR Section 3.1.2.4, Environmental and Missile Design Bases (Criterion 4).

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

  Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the SSC important to safety are designed.

- GDC-5 is described in FSAR Section 3.1.2.5, Sharing of Structures, Systems and Components (Criterion 5).

  The MPS3 residual heat removal system (RHS) is a unit specific system. It is not a shared system.

- GDC-34 is described in FSAR Section 3.1.2.34, Residual Heat Removal (Criterion 34).

  The residual heat removal system, in conjunction with the steam and power conversion system, is designed to transfer the fission product decay heat and other residual heat from the reactor core within acceptable limits. The transfer of the heat removal function from the steam and power conversion system to the residual heat removal system occurs when the reactor coolant system is at approximately 350°F and 375 psig.

  Suitable redundancy at temperatures below approximately 350°F is accomplished with the two residual heat removal pumps (located in separate compartments with means available for draining and monitoring of leakage), the two heat exchangers and the associated piping, cabling, and electric power sources. The residual heat removal system is able to operate on either onsite or offsite electrical power system.

  Suitable redundancy at temperatures above approximately 350°F is provided by the steam generators and associated piping system.

The RHS is described in the FSAR Section 5.4.7, including the degree of compliance to BTP RSB 5-1.

RHS operation for normal conditions and major failures is accomplished from the control room with limited operator action outside the control room. The redundancy in the RHS design provides the system with the capability to maintain its cooling function even with a major single failure, such as failure of a residual heat removal pump, valve, heat exchanger or an emergency power source, without impact on the redundant train's continued heat removal. The only effect would be an extension of the time required for cooldown. The RHS capability is demonstrated in FSAR Table 5.4-9. The MPS3 licensing basis for SGCS is cold shutdown within 66 hours of a reactor trip (achieve RHS entry conditions within 36 hours of reactor trip and cooldown the RCS from 350 °F to 200 °F within 30 hours on one RHS train.

The Technical Specifications (3.4.1.3, 3.4.1.4.1 and 3.4.1.4.2) ensure that sufficient heat removal capability exists for removing core decay heat. Information related to potential intersystem leakage outside containment (NUREG-0737, Item III.D.1.1) is provided in the FSAR Section 5.2.5. Technical Specification 3.7.1.3 ensures an adequate volume in the demineralized water storage tank (DWST) to support hot standby conditions with subsequent RCS cooldown.

The RHS was evaluated for the continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005 defines the scope of license renewal. NUREG-1838 Sections 2.3B.2.4 and 3.2B.2.3.4 are applicable to the RHS.

2.8.4.4.2 Technical Evaluation

2.8.4.4.2.1 Introduction

The RHS is designed to remove residual and sensible heat to reduce RCS temperature during the second phase of plant cooldown. This second cooldown phase starts when RHS entry conditions have been achieved (i.e., a 350°F RCS temperature and 375 psig RCS pressure). Portions of the RHS support ECCS design functions. During plant cooldown, a portion of the RCS flow is diverted to the CVCS for RCS purification and inventory/pressure control. The RHS is also used during refueling operation to transfer borated water from the refueling water storage tank (RWST) to the refueling cavity. The RHS pumps perform no containment heat removal or ECCS sump recirculation phase support functions.

The SPU results in a higher decay heat load for the RHS during cooldown operation. A CCP design change to increase operating temperatures during cooldown operation will offset impacts on cooldown times.

RCS reduced inventory operation (mid-loop operation) is discussed in Section 2.8.7.3.

2.8.4.4.2.2 Description of Analysis and Evaluations

2.8.4.4.2.2.1 Normal Cooldown

For normal cooldown, RCS temperature is reduced from the no load temperature (557°F) to RHS entry conditions (350°F) within 4-hours. Based upon two RHS heat exchangers and two RHS pumps in-service, the current RHS design is a functional capability that reduces RCS temperature from 350°F to 200°F within 20 hours (FSAR Section 5.4.7.1). This functional capability corresponds to cold shutdown conditions within 24-hours after reactor shutdown. With one RHS heat exchanger and one RHS pump aligned for ECCS operation until a 260°F RCS temperature, the RHS is currently designed to reduce the RCS temperature from 350°F to 200°F within 60-hours (FSAR Section 5.4.7.1) with one reactor coolant pump operating.

2.8.4.4.2.2.2 Safety Grade Cold Shutdown Cooldown Analysis

As discussed in FSAR Section 5.4.7.2.3.5 and TRM 7.6, SGCS is defined as the ability to take the plant from normal operating conditions to cold shutdown in a reasonable time period in accordance with the MPS3 response to BTP RSB 5-1. The MPS3 SGCS event is postulated to occur as a result of a SSE, coincident with a loss of offsite power, and a safety-related electrical distribution system train failure. The train failure disables multiple safe shutdown components, including one RHS train. Thus, SGCS is a natural circulation RCS cooldown event.

As defined in FSAR Section 5.4.7.2.3.5, a reasonable time period to cold shutdown was defined as 66-hours after reactor shutdown. This licensing amendment defines 72-hours after reactor shutdown as a reasonable time period to cold shutdown for BTP RSB 5-1 design purposes. The SGCS cooldown times remain acceptable regarding BTP RSB 5-1 requirements and the 72-hour cold shutdown criteria, as defined in this license amendment.

The SGCS analysis credits design functions performed by the CVCS, main steam system (MSS), reactor head vent letdown sub-system, RCS, auxiliary feedwater system (AFW), main feedwater system (FWS), low pressure safety injection (SIL) system, CCP, charging pump component cooling water system (CCI), service water system (SWP) and HVAC systems.

DWST inventory requirements are the major SPU impact on the SGCS analysis (refer to Section 2.5.4.5, Auxiliary Feedwater System). Section 2.8.7.2, Natural Circulation Cooldown also supports the conclusion that SPU has no adverse impact on SGCS capability.

2.8.4.4.2.2.3 Fire Shutdown Cooldown Analysis

As documented in Section 2.5.1.4, Fire Protection, DNC completed an SPU fire shutdown cooldown analysis demonstrating that BTP 9.5-1's 72-hour cooldown criterion to cold shutdown is satisfied given the new SPU decay heat load. This fire shutdown cooldown analysis is based upon the SGCS analysis design inputs/process parameters.

2.8.4.4.2.2.4 Other RHS Design Features/Considerations

The following design features/considerations have been reviewed and found acceptable: reactor vessel cold overpressure functional requirements associated with RHR pump suction relief valves (3RHS*RV8708A/B); RHS design features to provide protection from inadvertent overpressurization; RHS pump minimum flow protection; RHS piping system pressure and temperature design conditions; RHS failure modes and effects (FMEA) analysis; RHS high energy line break (HELB) and internal flooding design; valves; RHS instrumentation and control systems; and containment isolation design features.

2.8.4.4.2.2.5 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal safety evaluation report for the RHS. As stated in Section 2.8.4.4.1, the RHS is within the scope of License Renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with the operation of the RHS at SPU conditions and the SPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus no new aging effects requiring management were identified.

2.8.4.4.2.2.6 Results

A reactor plant component cooling water system design change is required at SPU conditions to offset the higher decay heat load. This change will increase the piping system maximum operating and design temperature (Table 2.8.4.4-2 for details). The SPU analysis demonstrates acceptable normal, abnormal, SGCS cooldown (Table 2.8.4.4-1), and fire shutdown cooldown results.

To address the small design margin for the two train available SGCS case, DNC proposes to define a reasonable SGCS cold shutdown time as 72-hours after reactor shutdown. The two train available case has longer cooldown times than the single train case, because operator action outside the control room to periodically adjust RHR heat exchanger bypass flow control valves (3RHS*FCV618/619) is not credited for the two train case.

2.8.4.4.3 Conclusion

DNC has evaluated the effects of the proposed SPU on the functional design of the residual heat removal system. DNC concludes that the evaluation adequately accounts for the effect of the proposed SPU on this system. DNC further concludes that the residual heat removal system will continue to meet the MPS3 current licensing basis with respect to the requirements of GDCs -4, -5, and -34 and BTP RSB 5-1. This conclusion includes the proposed design change that increases reactor plant component cooling water system operating temperatures during the cooldown mode of operation. Therefore, DNC finds the proposed SPU acceptable with respect to the residual heat removal system.

Table 2.8.4.4-1
Cooldown Analysis Results

Scenario	Current		SPU	
	Cooldown Time to 200°F (hours)	Concurrent Steaming Period (hours)	Cooldown Time to 200°F (hours)	Concurrent Steaming Period (hours)
Normal Cooldown - RHS Entry at 4-hours, Second Train Sequenced On At 260°F, One RCP Running	58	28	20	3
Normal Cooldown - RHS Entry at 4-hours, Second Train Sequenced On At 350°F, One RCP Running	12	0	7	0
Normal Cooldown - RHS Entry at 4-hours, Second Train Sequenced On At 260°F, Two RCPs Running to 160°F	122	74	34	11
Normal Cooldown - RHS Entry at 4-hours, Second Train Sequenced On At 350°F, Two RCPs Running to 160°F	17	0	8	0
SGCS - One Train Available, Instrument Air Unavailable (periodic local adjustment of RHR heat exchanger flow control bypass valves 3RHS*FCV618/619)	48	7	49.25	10.5
SGCS - Two Trains Available, Instrument Air Unavailable (no local adjustment of RHR heat exchanger flow control bypass valves 3RHS*FCV618/619)	55.25	5	64	8.5
Normal Cooldown with Only One RHS Train Available, Instrument Air Available, Significant Steam Releases To 8-Hours after Reactor Shutdown	Not Analyzed	Not Analyzed	29	8
Note: Cooldown times are relative to reactor shutdown.				

Table 2.8.4.4-2
Proposed Cooldown Related Design Changes

Design Parameter	Current		SPU	
	Normal Cooldown	SGCS	Normal Cooldown	SGCS
RHR Heat Exchanger CCP Return Piping Maximum Operating Temperature	130°F	140°F	145°F	145°F
RHR Heat Exchanger CCP Return Piping System Stress Analyzed Temperature	150°F		160°F	
RHR Heat Exchanger CCP Return Piping High Temperature Nominal Trip Setpoint (RHR heat exchanger flow control bypass valves 3RHS*FCV618/619 open)	145°F		155°F	
RHR Heat Exchanger CCP Return Piping High Temperature Nominal Alarm Setpoint	140°F		150°F	
CCP Supply Header Maximum Operating Temperature Limit	95°F	113°F	105°F	113°F
CCP Heat Exchanger SW Return Line Maximum Operating Temperature	125°F	125°F	125°F	125°F

Table 2.8.4.4-3
Normal Cooldown Analysis Details Second RHS Train Aligned at 260 F; One Reactor Coolant Pump Running

Parameter	Current	SPU
Elapsed time to RHR entry (hr)	4	4
Elapsed time to 200°F (hr)	58	20
Elapsed time to 140°F (hr)	60.5	23.25
Concurrent Steaming Period (hr)	28	3
Reactor Coolant System		
Initial Power Level (MWt)	3479 (102%)	3650 (100%)
Decay Heat Model	ANS 5.1-1979, with 2σ uncertainty	ANS 5.1-1979, with zero uncertainty
RCS Thermal Capacitance (MBtu/°F)	2.01	2.01
Residual Heat Removal System		
Max RHR HX Flow (gpm)	2950	2950
RHS HX UA (MBtu/hr-°F)	3.3	3.3
Reactor Plant Component Cooling Water System		
CCP HX Flow (lbm/hr $\times 10^6$) [lead train]	3.4	3.4
CCP HX Flow (lbm/hr $\times 10^6$) [follow train]	4.0	4.0
CCP SFP HX Flow (gpm)	1800	1800
CCP Max RHS HX Outlet Temp (°F)	130	145
CCP Supply Header Max Temp (°F)	95	105
CCP HX UA (MBtu/hr-°F)	3.91	3.93
Aux. Heat Load (MBtu/hr) [lead train]	2.6	2.6
Aux. Heat Load (MBtu/hr) [follow train]	27	23.8
Service Water System		
Service Water Flow to CCP Heat Exchanger (gpm)	6859	9000
Service Water Temperature (°F)	75	75
Spent Fuel Pool Cooling		
SFP HX UA (MBtu/hr-°F)	1.34	1.34

Table 2.8.4.4-3
Normal Cooldown Analysis Details Second RHS Train Aligned at 260 F; One Reactor Coolant Pump Running

Parameter	Current	SPU
SFC Flow (gpm)	3500	3500
SFP Decay Heat Load Associated With SFC System (MBtu/hr)	23.6	20.4

Table 2.8.4.4-4
Normal Cooldown Analysis Details Two RHS Trains Aligned at 350 F;
One Reactor Coolant Pump Running

Parameter	Current	SPU
Elapsed time to RHR entry (hr)	4	4
Elapsed time to 200ºF (hr)	12	7
Elapsed time to 140ºF (hr)	28.25	20.25
Concurrent Steaming Period (hr)	0	0
Reactor Coolant System		
Initial Power Level (MWt)	3479 (102%)	3650 (100%)
Decay Heat Model	ANS 5.1-1979, with 2σ uncertainty	ANS 5.1-1979, with zero uncertainty
RCS Thermal Capacitance (MBtu/°F)	2.01	2.01
Residual Heat Removal System		
Max RHR HX Flow (gpm)	2950	2950
RHS HX UA (MBtu/hr-°F)	3.3	3.3
Reactor Plant Component Cooling Water System		
CCP HX Flow (lbm/hr $\times$ 10^6) [lead train]	3.4	3.4
CCP HX Flow (lbm/hr $\times$ 10^6) [follow train]	4.0	4.0
CCP SFP HX Flow (gpm)	1800	1800
CCP Max RHS HX Outlet Temp (°F)	130	145
CCP Supply Header Max Temp (°F)	95	105
CCP HX UA (MBtu/hr-°F)	3.91	3.93
Aux. Heat Load (MBtu/hr) [lead train]	2.6	2.6
Aux. Heat Load (MBtu/hr) [follow train]	27	23.8
Service Water System		
Service Water Flow to CCP Heat Exchanger (gpm)	6859	9000
Service Water Temperature (°F)	75	75
Spent Fuel Pool Cooling		
SFP HX UA (MBtu/hr-°F)	1.34	1.34

Table 2.8.4.4-4
Normal Cooldown Analysis Details Two RHS Trains Aligned at 350 F;
One Reactor Coolant Pump Running

Parameter	Current	SPU
SFC Flow (gpm)	3500	3500
SFP Decay Heat Load Associated With SFC System (MBtu/hr)	23.6	20.4

Table 2.8.4.4-5
SGCS Cooldown Analysis Details One Train Available, Instrument Air Unavailable (periodic local adjustment of RHS heat exchanger flow control bypass valves 3RHS*FCV618/619)

Parameter	Current	SPU
Elapsed time to RHR entry (hr)	11	11
Elapsed time to 200ºF (hr)	48	49.25
Elapsed time to 140°F (hr)	N/A	N/A
Concurrent Steaming Period (hr)	7	10.5
Reactor Coolant System		
Initial Power Level (MWt)	3479 (102%)	3723 (102%)
Decay Heat Model	ANS 5.1-1979, with 2σ uncertainty	ANS 5.1-1979, with 2σ uncertainty
RCS Thermal Capacitance (MBtu/°F)	2.01	2.01
RCS Maximum Cooldown Rate (°F/hr)	50	50
Residual Heat Removal System		
Max RHR HX Flow (gpm)	2950	2950
RHS HX UA (MBtu/hr-°F)	3.3	3.3
Reactor Plant Component Cooling Water System		
CCP HX Flow (lbm/hr $\times 10^6$) [lead train]	4.0	4.0
CCP HX Flow (lbm/hr $\times 10^6$) [follow train]	N/A	N/A
CCP SFP HX Flow (gpm)	1800	1800
CCP Max RHS HX Outlet Temp (°F)	140	145
CCP Supply Header Max Temp (°F)	109	109
CCP HX UA (MBtu/hr-°F)	3.91	3.93
Aux. Heat Load (MBtu/hr) [lead train]	27	23.8
Aux. Heat Load (MBtu/hr) [follow train]	N/A	N/A
Service Water System		
Service Water Flow to CCP Heat Exchanger (gpm)	6859	7388
Service Water Temperature (°F)	75	75

Table 2.8.4.4-5
SGCS Cooldown Analysis Details One Train Available, Instrument Air Unavailable (periodic local adjustment of RHS heat exchanger flow control bypass valves 3RHS*FCV618/619)

Parameter	Current	SPU
Spent Fuel Pool Cooling		
SFP HX UA (MBtu/hr-°F)	1.34	1.34
SFC Flow (gpm)	3500	3500
SFP Decay Heat Load Associated With SFC System (MBtu/hr)	23.6	20.4

Table 2.8.4.4-6
SGCS Cooldown Analysis Details Two Trains Available; Instrument Air Unavailable (no local adjustment of RHS heat exchanger flow control bypass valves 3RHS*FCV618/619)

Parameter	Current	SPU
Elapsed time to RHR entry (hr)	11	11
Elapsed time to 200°F (hr)	55.25	64
Elapsed time to 140°F (hr)	N/A	N/A
Concurrent Steaming Period (hr)	5	8.5
Reactor Coolant System		
Initial Power Level (MWt)	3479 (102%)	3723 (102%)
Decay Heat Model	ANS 5.1-1979, with 2σ uncertainty	ANS 5.1-1979, with 2σ uncertainty
RCS Thermal Capacitance (MBtu/°F)	2.01	2.01
RCS Maximum Cooldown Rate (°F/hr)	50	50
Residual Heat Removal System		
Max RHR HX Flow (gpm)	850	850
RHS HX UA (MBtu/hr-°F)	3.3	3.3
Reactor Plant Component Cooling Water System		
CCP HX Flow (lbm/hr $\times 10^6$) [lead train]	3.4	3.4
CCP HX Flow (lbm/hr $\times 10^6$) [follow train]	4.0	4.0
CCP SFP HX Flow (gpm)	1800	1800
CCP Max RHS HX Outlet Temp (°F)	140	145
CCP Supply Header Max Temp (°F)	101	100
CCP HX UA (MBtu/hr-°F)	3.91	3.93
Aux. Heat Load (MBtu/hr) [lead train]	2.6	2.6
Aux. Heat Load (MBtu/hr) [follow train]	27	23.8
Service Water System		
Service Water Flow to CCP Heat Exchanger (gpm)	6859	7388
Service Water Temperature (°F)	75	75

Table 2.8.4.4-6
SGCS Cooldown Analysis Details Two Trains Available; Instrument Air Unavailable (no local adjustment of RHS heat exchanger flow control bypass valves 3RHS*FCV618/619)

Parameter	Current	SPU
Spent Fuel Pool Cooling		
SFP HX UA (MBtu/hr-°F)	1.34	1.34
SFC Flow (gpm)	3500	3500
SFP Decay Heat Load Associated With SFC System (MBtu/hr)	23.6	20.4

2.8.5 Accident and Transient Analyses

2.8.5.0 Introduction

This section summarizes the transient analyses and evaluations performed to support the SPU program for MPS3.

2.8.5.0.1 Classification of Events

Since 1970, the classification of plant conditions in American Nuclear Society Standard ANSI N18.2-1973 (Reference 1) has often been used to facilitate the evaluation of nuclear plant safety and the functional requirements for structures, systems, and components. The plant conditions are divided into four categories in accordance with the anticipated frequencies of occurrence and potential radiological consequences. The four categories (or conditions) are:

- Condition I – Normal Operation and Operational Transients
- Condition II – Faults of Moderate Frequency
- Condition III – Infrequent Faults
- Condition IV – Limiting Faults

The basic principle applied in relating requirements to each of the conditions is that the most probable occurrences should yield the least radiological risk to the public, and those extreme situations having the potential for greatest risk to the public shall be those least likely to occur. Where applicable, reactor trip system and engineered safeguards functioning is assumed to the extent allowed by considerations such as the single failure criterion, in fulfilling this principle. Each condition is described in more detail as follows.

Condition I – Normal Operation and Operational Transients

Condition I occurrences are those that are expected frequently or regularly during power operation, refueling, maintenance, or maneuvering of the plant. Condition I occurrences are accommodated with margin between any plant parameter and the value of the parameter that would require either automatic or manual protective action. In this regard, analysis of the fault condition is typically based on a conservative set of initial conditions corresponding to the most adverse set of conditions occurring during Condition I operation. The FSAR Section 15.0.1.1 provides a typical list of Condition I events.

Condition II – Faults of Moderate Frequency

These faults, at worst, result in a reactor trip with the plant being capable of returning to operation after corrective action. A Condition II fault (or event), by itself, does not propagate to a more serious incident of the Condition III or Condition IV type without the occurrence of other independent incidents. A single Condition II incident should not cause the loss of any barrier to the escape of radioactive products. The Condition II events for MPS3 are listed in FSAR Section 15.0.1.2.

Condition III – Infrequent Faults

Condition III faults occur very infrequently during the life of the plant. Condition III faults can be accommodated with the failure of only a small fraction of the fuel rods, although sufficient fuel damage might occur to preclude resumption of operation for a considerable outage time. The release of radioactivity due to Condition III faults will not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. A Condition III fault does not, by itself, generate a Condition IV fault or result in a consequential loss of function of the RCS or containment barriers. FSAR Section 15.0.1.3 provides the list of events in this category.

Condition IV – Limiting Faults

Condition IV occurrences are faults that are not expected to occur, but are postulated because their consequences have the potential for the release of significant amounts of radioactive material. Condition IV faults are the most drastic occurrences that must be designed against, and represent the limiting design cases. Condition IV faults should not cause a fission product release to the environment resulting in an undue risk to public health and safety in excess of the guideline values of 10 CFR 50.67. A single Condition IV fault is not to cause a consequential loss of required functions of systems needed to cope with the fault, including those of the emergency core cooling system and the containment. The Condition IV events for MPS3 are listed in FSAR Section 15.0.1.4.

2.8.5.0.2 Optimization of Control Systems

Evaluations or analyses of the MPS3 control systems were performed for the SPU. Section 2.4 discusses these evaluations/analyses. The accident analyses performed for the SPU have included the results of the control systems evaluations/analyses as appropriate for the event being analyzed.

2.8.5.0.3 Plant Characteristics and Initial Conditions Assumed in the Accident Analyses

2.8.5.0.3.1 SPU Plant Conditions

Key features of the power uprate program that were considered in the safety analyses are as follows:

- A nuclear steam supply system (NSSS) power level of 3666 MWt (includes a net RCS heat of 16 MWt),
- A nominal, full-power reactor coolant vessel average temperature (T_{avg}) window between 571.5°F and 589.5°F,
- A reactor coolant system (RCS) thermal design flow (TDF) of 363,200 gpm (90,800 gpm/loop), and a minimum measured flow (MMF) of 379,200 gpm (94,800 gpm/loop).
- Uniform steam generator tube plugging (SGTP) levels of 0 percent and 10 percent,
- A nominal operating pressurizer pressure of 2250 psia,

- A design core bypass flow of 8.6 percent (non-RTDP analyses) and a statistical core bypass flow of 7.59 percent (RTDP analyses), assuming core thimble plugs are removed (this is conservative with respect to the current plant condition with thimble plugs installed),
- Nominal, full-power main feedwater temperatures of 390°F and 445.3°F.

The uprated NSSS power level of 3666 MWt (3650 MWt core power + 16 MWt RCS net heat input) is conservative. A best estimate calculation has been performed that determined that the RCS net heat input is approximately 17 MWt. Since core power is derived from measurement of NSSS power, it is conservative to assume a slightly lower value of 16 MWt RCS net heat input. This is conservative because when the lower net RCS heat input is subtracted from the measured NSSS power it will limit the core power to approximately 3649 MWt.

Table 2.8.5.0-1 lists the principal power rating values which are assumed in the analyses. The thermal power values used for each transient analyzed are given in Table 2.8.5.0-2. The values of other pertinent plant parameters utilized in the accident analyses are given in Table 2.8.5.0-3.

2.8.5.0.3.2 Initial Conditions

As in the current MPS3 licensing basis, for most transients that were analyzed for departure from nucleate boiling (DNB) concerns, the Revised Thermal Design Procedure (RTDP) methodology (Reference 2) was employed (See Section 2.8.3). With this methodology, nominal values are assumed for the initial RCS conditions of power, temperature, pressure, and flow, and the corresponding uncertainty allowances are accounted for statistically in defining the DNBR safety analysis limit. Note that the nominal RCS flow modeled in RTDP transient analyses is the MMF of 379,200 gpm.

As discussed in Section 2.8.3 uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions were combined statistically to obtain the overall DNB uncertainty factor, which was used to define the plant-specific design limit DNBR. To provide DNBR margin to offset various penalties such as those due to rod bow and instrument bias, and to provide flexibility in design and operation of the plant, the design limit DNBR was conservatively increased to a value designated as the safety analysis limit DNBR, to which transient-specific DNBR values were compared. Section 2.8.3.2.5 provides the design limit and safety limit DNBR values.

For transient analyses that are not DNB-limited, or for which RTDP is not employed, the initial conditions were obtained by applying the maximum, steady-state uncertainties to the nominal values in the most conservative direction; this is known as Standard Thermal Design Procedure (STDP), or non-RTDP. In these analyses, the RCS flow was assumed to be equal to the TDF, and the following steady-state initial condition uncertainties were considered.

- $\pm$2.0 percent NSSS power allowance for calorimetric measurement uncertainty.
- $\pm$4°F T_{avg} allowance for instrumentation, rod control deadband and cold leg streaming. The calculated values are $\pm$3°F random, $\pm$1°F bias.
- $\pm$50 psi pressurizer pressure allowance for instrumentation, control system overshoot and transmitter bias. The calculated values are $\pm$31.8 psi random, $\pm$15 psi bias.

Table 2.8.5.0-2 summarizes the initial conditions and computer codes used in the accident analyses.

2.8.5.0.3.3 Power Distribution

The transient response of the reactor system is dependent on the initial power distribution. The nuclear design of the reactor core minimizes adverse power distribution through the placement of control rods and operating instructions. Power distribution may be characterized by the radial peaking factor ($F^N_{\Delta H}$) and the total peaking factor (F_q). For the SPU, the power distribution is characterized by an $F^N_{\Delta H}$ of 1.650, and an $F_{\Delta q}$ of 2.60. The peaking factor limits are discussed in Section 2.8.3.

For transients that may be DNB limited, the radial peaking factor is of importance. The radial peaking factor increases with decreasing power level due to rod insertion, as defined by the equation in Table 2.8.3-1. All transients that may be DNB limited are assumed to begin with an $F^N_{\Delta H}$ consistent with that defined by this limiting equation for the assumed power level. For transients that may be overpower limited, the total peaking factor (F_q) is of importance.

2.8.5.0.4 Reactivity Coefficients

The transient response of the reactor core is dependent on reactivity feedback effects, in particular the moderator temperature coefficient (MTC) and the Doppler power coefficient (DPC). In the analysis of certain events, conservatism requires the use of maximum reactivity coefficient values, whereas in the analysis of other events, conservatism requires the use of minimum reactivity coefficient values. The values used are given in Table 2.8.5.0-2. Reference is made in that table to Figure 2.8.5.0-2, which shows the upper and lower bound DPCs as a function of power, used in the transient analysis. Justification for the use of the reactivity coefficient values was treated on an event-specific basis. In some cases, conservative combinations of parameters are used to bound the effects of core life. Table 2.8.5.0-4 summarizes the core kinetics parameters and reactivity feedback coefficients assumed in the analyses.

The bounding reactivity coefficients given in Table 2.8.5.0-2 and Figure 2.8.5.0-2 are confirmed to remain bounding on a cycle-by-cycle basis as part of the normal reload process.

2.8.5.0.5 RCCA Insertion Characteristics

The negative reactivity insertion following a reactor trip is a function of the acceleration of the RCCAs and the variation in rod worth as a function of rod position. With respect to the accident analyses, the critical parameter is the time from the start of RCCA insertion to when the RCCAs reach the dashpot region, which is located at an insertion point corresponding to approximately 85 percent of the total RCCA travel distance. The RCCA position versus time assumed in accident analysis is shown in Figure 2.8.5.0-3. The RCCA insertion time from fully withdrawn to dashpot entry was modeled as 2.7 seconds, unless otherwise noted in the discussion for a particular event.

Figure 2.8.5.0-4 shows the fraction of total negative reactivity insertion versus normalized rod position for a core where the axial distribution is skewed to the lower region of the core. An axial distribution that is skewed to the lower region of the core can arise from an unbalanced xenon distribution. This curve is used to compute the negative reactivity insertion versus time following a reactor trip which is input to all point kinetics core models used in transient analyses. The bottom skewed power distribution itself is not an input into the point kinetics core model.

The normalized RCCA negative reactivity insertion versus time is shown on 2.8.5.0-5. The curve shown on this figure was obtained from Figures 2.8.5.0-3 and 2.8.5.0-4. A total negative reactivity insertion of 4 percent following a trip is assumed in the transient analyses except where specifically noted otherwise.

2.8.5.0.6 Trip Points and Time Delays to Trip Assumed in Accident Analyses

A reactor trip signal acts to open two trip breakers connected in series feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the RCCAs, which then fall by gravity into the core. There are various instrumentation delays associated with each trip function, including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are free and begin to fall. Limiting trip setpoints assumed in accident analyses and the time delay assumed for each trip function are given in Table 2.8.5.0-5.

The safety analysis limit (SAL) for the power range high neutron flux (high setting) was reduced from 118 percent in the current FSAR Table 15.0-4 to 116.5 percent for the RCCA withdrawal at power event (Table 2.8.5.4.2). As noted in Section 2.4.1, the current field trip setpoint of 109 percent has adequate margin to accommodate this reduced SAL. Another change from the SAL values in the FSAR Table 15.0-4 is the low-low steam generator water level for the loss of normal feedwater/loss of off-site power event. The analyses for this event for the SPU supports an SAL of 0 percent narrow range span, consistent with the value for the feedline break event. Also, as discussed below, the overtemperature and overpower ΔT (OTΔT / OPΔT) reactor trip setpoints have been revised for the SPU (see further discussion in Section 2.4.1).

The OTΔT/OPΔT reactor trip setpoints were recalculated using the methodology described in WCAP-8745-P-A (Reference 3). Conservative core thermal limits developed using the RTDP methodology (as described in Licensing Report Section 2.8.3) were used to calculate the OTΔT and OPΔT reactor trip setpoints. The OTΔT and OPΔT trip setpoints are illustrated in Figure 2.8.5.0-1 and presented in Table 2.8.5.0-6.

The boundaries of operation defined by the OTΔT and OPΔT trips are represented as “protection lines” on Figure 2.8.5.0-1. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that, under nominal conditions, a trip would occur well within the area bounded by these lines. These protection lines are based upon the safety analysis limit OTΔT and OPΔT setpoint values, which are essentially the Technical Specification nominal values with allowances for instrumentation errors and acceptable drift between instrumentation calibrations. The utility of this diagram is in the fact that the limit imposed by any given DNBR can be represented as a line (ΔT versus T_{avg}). The DNB lines represent the locus of conditions for which DNBR equals the limit value. All points below and to the left of a DNB line for a given pressure have a DNBR greater than the limit value.

The area of permissible operation (power, pressure, and temperature) is bounded by the combination of the high neutron flux (fixed setpoint), high- and low-pressurizer pressure (fixed setpoints), and OTΔT and OPΔT (variable setpoints) reactor trips, and the opening of the main steam safety valves (MSSVs), which limit the maximum RCS average temperature. The adequacy of the OTΔT and OPΔT setpoints was confirmed by demonstrating that the DNB design basis was met for those transients analyzed for DNB concerns.

The difference between the limiting trip point assumed for the analysis and the nominal trip point represents an allowance for instrumentation channel error and setpoint error. Nominal trip setpoints are specified in the plant Technical Specifications. During plant startup tests, it was demonstrated that actual instrument time delays are equal to or less than the assumed values. Additionally, protection system channels are calibrated and instrument response times determined periodically in accordance with the plant Technical Specifications.

2.8.5.0.7 Plant Systems and Components Available for Mitigation of Accident Effects

The NSSS is designed to afford proper protection against the possible effects of natural phenomena, postulated environmental conditions and dynamic effects of the postulated accidents. In addition, the design incorporates features that minimize the probability and effects of fires and explosions. The incorporation of these features in the NSSS, coupled with the reliability of the design, ensures that the normally operating systems and components listed in Table 2.8.5.0-7 are available for mitigation of the events discussed in the FSAR Chapter 15. In determining which systems are necessary to mitigate the effects of these postulated events, the classification system of ANSI-N18.2-1973 is utilized. The design of “systems important to safety” (including protection systems) is consistent with IEEE Standard 379-1972 and RG 1.53 in the application of the single failure criterion.

In the analysis of FSAR Chapter 15 events, control system action is considered only if that action results in more severe accident results. No credit is taken for control system operation if that operation mitigates the results of an accident. For some accidents, the analysis is performed both with and without control system operation to determine the worst case.

2.8.5.0.8 Fission Product Inventories

The core inventory is revised to reflect the SPU conditions. Table 2.9.2-1 provides the core inventory associated with the power uprate. This table will replace FSAR Table 15.0-7. It was generated using the ORIGEN code. ORIGEN is part of the SCALE computer code system. The isotopes and the associated curies at the end of a fuel cycle were input to RADTRAD-NAI. The CEDE and EDE dose conversion factors were taken from Federal Guidance Reports 11 and 12.

2.8.5.0.9 Residual Decay Heat

2.8.5.0.9.1 Total Residual Heat

Residual heat in a subcritical core is calculated for the small break LOCA per the requirements of 10 CFR 50.46, Appendix K (10 CFR 50.46 and 10 CFR 50, Appendix K), as described in WCAP-10054, 1985. These requirements include assuming infinite irradiation time before the core goes subcritical to determine fission product decay energy. For all other accidents, unless noted otherwise, the same models are used except that fission product decay energy is based on core average exposure at the end of the equilibrium cycle.

2.8.5.0.9.2 Decay Heat Modeling for a Small Break Loss-of-Coolant Accident

During a LOCA, the core is rapidly shut down by void formation or RCCA insertion, or both, and a large fraction of the heat generation to be considered comes from fission product decay gamma rays. This heat is not distributed in the same manner as steady state fission power. Local peaking effects that are important for the neutron dependent part of the heat generation do not apply to the gamma ray contribution. The steady state factor of 97.4 percent, which represents the fraction of heat generated within the clad and pellet, drops to 95 percent for the hot rod in a LOCA.

2.8.5.0.9.3 Decay Heat Modeling for a Best Estimate Large Break LOCA

The decay heat model within WCOBRA/TRAC is described in detail in Section 8 of WCAP-16009-P-A. The model has been benchmarked against the ANSI/ANS 5.1-1979 Standard. WCOBRA/TRAC solves for the composite decay heat of the reactor using the fission rate fractions derived from specific physics calculations for the fuel lattice design. The decay heat modeling for the large break LOCA methodology has been approved for use in WCAP-16009-P-A.

2.8.5.0.10 Computer Codes Utilized

Summary descriptions of the principal computer codes used in transient analyses are provided below. Other codes, in particular very specialized codes in which the modeling has been developed to simulate one given accident, such as those used in the analysis of the RCS pipe rupture (Section 2.8.5.6.3), are summarized in their respective accident analyses sections. The codes used in the analyses of each transient have been listed in Table 2.8.5.0-2.

FACTRAN

FACTRAN calculates the transient temperature distribution in a cross-section of a metal-clad UO_2 fuel rod, and the transient heat flux at the surface of the cladding, using as input the nuclear power and the time-dependent coolant parameters of pressure, flow, temperature, and density. The code uses a fuel model with the following features:

- a sufficiently large number of radial space increments to handle fast transients such as an RCCA ejection accident,
- material properties that are functions of temperature,
- a sophisticated fuel-to-cladding gap heat transfer calculation, and
- calculations to address post-DNB conditions (film boiling heat transfer correlations, Zircaloy-water reaction, and partial melting of the fuel).

The FACTRAN licensing topical report, WCAP-7908-A (Reference 5), was approved by the NRC via a Safety Evaluation Report (SER) from C. E. Rossi (NRC) to E. P. Rahe (Westinghouse), dated September 30, 1986. The FACTRAN SER identifies seven conditions of acceptance, which are summarized below along with justifications for application to MPS3 for the SPU.

1. "The fuel volume-averaged temperature or surface temperature can be chosen at a desired value which includes conservatisms reviewed and approved by the NRC."

   Justification

   The FACTRAN code was used in the analyses of the following transients for the MPS3 SPU: Uncontrolled RCCA Withdrawal from a Subcritical Condition (Section 2.8.5.4.1) and RCCA Ejection (Section 2.8.5.4.6). Initial fuel temperatures used as FACTRAN input in the RCCA Ejection analysis were calculated using the NRC-approved PAD 4.0 computer code as described in WCAP-15063-P-A Revision 1 (Reference 6). As indicated in WCAP-15063-P-A Revision 1, the NRC has approved the method of determining uncertainties for PAD 4.0 fuel temperatures.

2. "Table 2 presents the guidelines used to select initial temperatures."

   Justification

   In summary, Table 2 of the SER specifies that the initial fuel temperatures assumed in the FACTRAN analyses of the following transients should be "High" and include uncertainties: Loss of Flow, Locked Rotor, and Rod Ejection. As discussed above, fuel temperatures were used as input to the FACTRAN code in the RCCA Ejection analysis for MPS3 at SPU conditions. The assumed fuel temperatures, which were calculated using the PAD 4.0 computer code (Reference 6), include uncertainties and are conservatively high. FACTRAN was not used in the Loss of Flow and Locked Rotor analyses for the SPU.

3. "The gap heat transfer coefficient may be held at the initial constant value or can be varied as a function of time as specified in the input."

   Justification

   The gap heat transfer coefficients applied in the FACTRAN analyses are consistent with SER Table 2. For the RCCA Withdrawal from a Subcritical Condition transient, the gap heat transfer coefficient is kept at a conservative constant value throughout the transient; a high constant value is assumed to maximize the peak heat flux (for DNB concerns) and a low constant value is assumed to maximize fuel temperatures. For the RCCA Ejection transient, the initial gap heat transfer coefficient is based on the predicted initial fuel surface temperature, and is ramped rapidly to a very high value at the beginning of the transient to simulate clad collapse onto the fuel pellet.

4. "…the Bishop-Sandberg-Tong correlation is sufficiently conservative and can be used in the FACTRAN code. It should be cautioned that since these correlations are applicable for local conditions only, it is necessary to use input to the FACTRAN code which reflects the local conditions. If the input values reflecting average conditions are used, there must be sufficient conservatism in the input values to make the overall method conservative."

   Justification

   Local conditions related to temperature, heat flux, peaking factors and channel information were input to FACTRAN for each transient analyzed for MPS3 at SPU conditions (RCCA Withdrawal from a Subcritical Condition (Section 2.8.5.4.1) and RCCA Ejection (Section 2.8.5.4.6)). Therefore, additional justification is not required.

5. "The fuel rod is divided into a number of concentric rings. The maximum number of rings used to represent the fuel is 10. Based on our audit calculations we require that the minimum of 6 should be used in the analyses."

   Justification

   At least 6 concentric rings were assumed in FACTRAN for each transient analyzed for MPS3 at SPU conditions (RCCA Withdrawal from a Subcritical Condition (Section 2.8.5.4.1) and RCCA Ejection (Section 2.8.5.4.6)).

6. "Although time-*independent* mechanical behavior (e.g., thermal expansion, elastic deformation) of the cladding are considered in FACTRAN, time-*dependent* mechanical behavior (e.g., plastic deformation) is not considered in the code. …for those events in which the FACTRAN code is applied (see Table 1), significant time-dependent deformation of the cladding is not expected to occur due to the short duration of these events or low cladding temperatures involved (where DNBR Limits apply), or the gap heat transfer coefficient is adjusted to a high value to simulate clad collapse onto the fuel pellet."

   Justification

   The two transients that were analyzed with FACTRAN for MPS3 at SPU conditions (RCCA Withdrawal from a Subcritical Condition (Section 2.8.5.4.1) and RCCA Ejection (Section 2.8.5.4.6)) are included in the list of transients provided in Table 1 of the SER; each of these transients is of short duration. For the RCCA Withdrawal from a Subcritical Condition transient, relatively low cladding temperatures are involved, and the gap heat transfer coefficient is kept constant throughout the transient. For the RCCA Ejection transient, a high gap heat transfer coefficient is applied to simulate clad collapse onto the fuel pellet. The gap heat transfer coefficients applied in the FACTRAN analyses are consistent with SER Table 2.

7. "The one group diffusion theory model in the FACTRAN code slightly overestimates at beginning of life (BOL) and underestimates at end of life (EOL) the magnitude of flux depression in the fuel when compared to the LASER code predictions for the same fuel enrichment. The LASER code uses transport theory. There is a difference of about 3 percent in the flux depression calculated using these two codes. When [T(centerline) – T(Surface)] is

on the order of 3000°F, which can occur at the hot spot, the difference between the two codes will give an error of 100°F. When the fuel surface temperature is fixed, this will result in a 100°F lower prediction of the centerline temperature in FACTRAN. We have indicated this apparent nonconservatism to Westinghouse. In the letter NS-TMA-2026, dated January 12, 1979, Westinghouse proposed to incorporate the LASER-calculated power distribution shapes in FACTRAN to eliminate this non-conservatism. We find the use of the LASER-calculated power distribution in the FACTRAN code acceptable."

Justification

The condition of concern (T(centerline) – T(surface) on the order of 3000°F) is expected for transients that reach, or come close to, the fuel melt temperature. As this applies only to the RCCA ejection transient, the LASER-calculated power distributions were used in the FACTRAN analysis of the RCCA ejection transient for MPS3 at SPU conditions.

RETRAN

RETRAN is used for studies of transient response of a pressurized water reactor (PWR) system to specified perturbations in process parameters. This code simulates a multi-loop system by a lumped parameter model containing the reactor vessel, hot- and cold-leg piping, RCPs, steam generators (tube and shell sides), main steam lines, and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves can also be modeled. RETRAN includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the steam generator uses a detailed nodalization for the thermal transients. The reactor trip system simulated in the code includes reactor trips on high neutron flux, high neutron flux rate, OTΔT, OPΔT, low reactor coolant flow, low reactor coolant pump speed, high- and low-pressurizer pressure, high pressurizer level, and low-low steam generator water level. Control systems are also simulated including rod control and pressurizer pressure control. Parts of the safety injection system (SIS), including the accumulators, are also modeled. Also, a conservative approximation of the transient DNBR, based on the core thermal limits, is calculated via RETRAN.

The RETRAN licensing topical report, WCAP-14882-P-A (Reference 7), was approved by the NRC via an SER from F. Akstulewicz (NRC) to H. Sepp (Westinghouse), dated February 11, 1999. The RETRAN SER identifies three conditions of acceptance, which are summarized below along with justifications for application to MPS3.

1. "The transients and accidents that Westinghouse proposes to analyze with RETRAN are listed in this SER (Table 1) and the NRC staff review of RETRAN usage by Westinghouse

was limited to this set. Use of the code for other analytical purposes will require additional justification."

Justification

The transients listed in Table 1 of the SER are:

Feedwater system malfunctions,
Excessive increase in steam flow,
Inadvertent opening of a steam generator relief or safety valve,
Steam line break,
Loss of external load/turbine trip,
Loss of offsite power,
Loss of normal feedwater flow,
Feedwater line rupture,
Loss of forced reactor coolant flow,
Locked reactor coolant pump rotor/sheared shaft,
Control rod cluster withdrawal at power,
Dropped control rod cluster/dropped control bank,
Inadvertent increase in coolant inventory,
Inadvertent opening of a pressurizer relief or safety valve,
Steam generator tube rupture.

The transients analyzed for MPS3 using RETRAN are:

Feedwater system malfunctions (Section 2.8.5.1.1),
Steam line break (Section 2.8.5.1.2),
Loss of external load/turbine trip (Section 2.8.5.2.1),
Loss of normal feedwater flow, with and without offsite power (Section 2.8.5.2.3),
Feedwater system pipe break (feedwater line rupture) (Section 2.8.5.2.4),
Loss of forced reactor coolant flow (Section 2.8.5.3.1),
Locked reactor coolant pump rotor/shaft break (Section 2.8.5.3.2),
Uncontrolled RCCA withdrawal at power (Section 2.8.5.4.2),
Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction

that Increases Reactor Coolant Inventory (Section 2.8.5.5),
Inadvertent opening of a pressurizer safety or relief valve (Section 2.8.5.6.1),

Since each transient analyzed for MPS3 using RETRAN matches one of the transients listed in Table 1 of the SER, additional justification is not required.

2. "WCAP-14882 describes modeling of Westinghouse designed 4-, 3, and 2-loop plants of the type that are currently operating. Use of the code to analyze other designs, including the Westinghouse AP600, will require additional justification."

   Justification

   MPS3 is a 4-loop Westinghouse-designed unit that was "currently operating" at the time the SER was written (February 11, 1999). Therefore, additional justification is not required.

3. "Conservative safety analyses using RETRAN are dependent on the selection of conservative input. Acceptable methodology for developing plant-specific input is discussed in WCAP-14882 and in Reference 14 [WCAP-9272-P-A]. Licensing applications using RETRAN should include the source of and justification for the input data used in the analysis."

   Justification

   The input data used in the RETRAN analyses performed by Westinghouse came from both DNC and Westinghouse sources. Assurance that the RETRAN input data is conservative for MPS3 is provided via Westinghouse's use of transient-specific analysis guidance documents. Each analysis guidance document provides a description of the subject transient, a discussion of the plant protection systems that are expected to function, a list of the applicable event acceptance criteria, a list of the analysis input assumptions (e.g., directions of conservatism for initial condition values), a detailed description of the transient model development method, and a discussion of the expected transient analysis results. Based on the analysis guidance documents, conservative plant-specific input values were requested and collected from the responsible DNC and Westinghouse sources. Consistent with the Westinghouse Reload Evaluation Methodology described in WCAP-9272-P-A (Reference 8), the safety analysis input values used in the MPS3 analyses were selected to conservatively bound the values expected in subsequent operating cycles.

LOFTRAN

Transient response studies of a PWR to specified perturbations in process parameters use the LOFTRAN computer code. This code simulates a multi-loop system by a model containing the reactor vessel, hot- and cold-leg piping, steam generators (tube and shell sides), the pressurizer and the pressurizer heaters, spray, relief valves, and safety valves. LOFTRAN also includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and rods. The secondary side of the steam generator uses a homogeneous, saturated mixture for the thermal transients. The code simulates the reactor trip system, which includes reactor trips on high neutron flux, OTΔT and OPΔT, high- and low-pressurizer pressure, low RCS flow, low-low steam generator water level, and high pressurizer level. Control systems are also simulated including rod control, steam dump, and pressurizer pressure control. The SIS, including the accumulators, is also modeled. LOFTRAN can also approximate the transient value of DNBR based on input from the core thermal safety limits.

The LOFTRAN licensing topical report, WCAP-7907-P-A (Reference 9), was approved by the NRC via an SER from C. O. Thomas (NRC) to E. P. Rahe (Westinghouse), dated July 29, 1983. The LOFTRAN SER identifies one condition of acceptance, which is summarized below along with justification for application to MPS3.

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

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

   This review is limited to the use of LOFTRAN for the licensee safety analyses of the Chapter 15 events listed above, and for a steam generator tube rupture…"

   Justification

   For the proposed MPS3 power uprate, the LOFTRAN code was used in the analyses of the dropped rod transient (Section 2.8.5.4.3) and steam line break mass and energy releases (Section 2.6.3.2). In addition, a modified version of LOFTRAN (LOFTRR2) was used for the steam generator tube rupture analysis (Section 2.8.5.6.2). As each of these transients match one of the transients listed in the SER, additional justification is not required.

TWINKLE

TWINKLE is a multi-dimensional spatial neutron kinetics code. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed multi-region fuel-cladding-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 8000 spatial points and performs steady-state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. The code provides various outputs, such as channelwise power, axial offset, enthalpy, volumetric surge, pointwise power, and fuel temperatures. It also predicts the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

The TWINKLE licensing topical report, WCAP-7979-P-A (Reference 10), was approved by the U.S. Atomic Energy Commission (AEC) via an SER from D. B. Vassallo (AEC) to R. Salvatori (Westinghouse), dated July 29, 1974. The TWINKLE SER does not identify any conditions, restrictions, or limitations that need to be addressed for application to MPS3.

Advanced Nodal Code (ANC)

ANC is an advanced nodal code capable of two-dimensional (2-D) and three-dimensional (3-D) neutronics calculations. ANC is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients, etc. In addition, 3-D ANC validates 1-D and 2-D results and provides information about radial (x-y) peaking factors as a function of axial position. It can calculate discrete pin powers from nodal information as well.

The ANC licensing topical report, WCAP-10965-P-A (Reference 11), was approved by the NRC via an SER from C. Berlinger (NRC) to E. P. Rahe (Westinghouse), dated June 23, 1986. The ANC SER does not identify any conditions, restrictions, or limitations that need to be addressed for application to MPS3.

VIPRE

The VIPRE computer program performs thermal-hydraulic calculations. This code calculates coolant density, mass velocity, enthalpy, void fractions, static pressure, and DNBR distributions along flow channels within a reactor core.

The VIPRE licensing topical report, WCAP-14565-P-A (Reference 12), was approved by the NRC via an SER from T. H. Essig (NRC) to H. Sepp (Westinghouse), dated January 19, 1999. The VIPRE SER identifies four conditions of acceptance, which are summarized below along with justification for application to MPS3.

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

   Justification

   The WRB-2M correlation with a 95/95 correlation limit of 1.14 was used in the DNB analyses for the MPS3 17x17 RFA/RFA-2 fuel type. The use of the WRB-2M DNB correlation for this fuel type was approved in the SER of WCAP-15025-P-A (Reference 13). Recent updated information for using WRB-2M was documented in a letter from D. S. Collins (NRC) to J. A. Gresham (Westinghouse) (Reference 14).

The use of the plant specific hot channel factors and other fuel dependent parameters in the DNB analysis for the MPS3 RFA fuel were justified using the same methodologies as for previously approved safety evaluations of other Westinghouse four-loop plants using the same fuel design.

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

   Justification

   The core boundary conditions for the VIPRE calculations for the MPS3 fuel are all generated from NRC-approved codes and analysis methodologies. Conservative reactor core boundary conditions were justified for use as input to VIPRE. Continued applicability of the input assumptions is verified on a cycle-by-cycle basis using the Westinghouse reload methodology described in WCAP-9272-P-A (Reference 8).

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

   Justification

   As discussed in the justification to the first VIPRE condition of acceptance, the WRB-2M correlation with a limit of 1.14 was used for the DNB analyses of the MPS3 fuel. For conditions where WRB-2M is not applicable, the WRB-2 or W-3 DNB correlation was used with the appropriate limits.

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

effects. The NRC Staff requires that appropriate justification be submitted with each usage of VIPRE in the post-CHF region to ensure that conservative results are obtained."

Justification

For application to MPS3 SPU safety analysis, the usage of VIPRE in the post-critical heat flux region is limited to the peak clad temperature calculation for the locked rotor transient. The calculation demonstrated that the peak clad temperature in the reactor core is well below the allowable limit to prevent clad embrittlement. VIPRE modeling of the fuel rod is consistent with the model described in WCAP-14565-P-A, which is for replacing FACTRAN (WCAP-7337) for the LR analysis, and included the following conservative assumptions:

- DNB was assumed to occur at the beginning of the transient
- Film boiling was calculated using the Bishop-Sandberg-Tong correlation
- The Baker-Just correlation accounted for heat generation in fuel cladding due to zirconium-water reaction

Conservative results were further ensured with the following input:

- Fuel rod input based on the maximum fuel temperature at the given power
- The hot spot power factor was equal to or greater than the design linear heat rate
- Uncertainties were applied to the initial operating conditions in the limiting direction

PHOENIX-P

PHOENIX-P is a two-dimensional, multi-group transport theory code which utilizes a 70 energy-group cross section library. It provides the capability for cell lattice modeling on an assembly level. It is used to provide homogenized, two-group cross sections for nodal calculations and feedback models. Additionally, PHOENIX-P is used to generate appropriately weighted constants for the baffle/reflector regions.

The PHOENIX-P licensing topical report, WCAP-11596-P-A (Reference 15), was approved by the NRC via an SER from A. C. Thadani (NRC) to W. J. Johnson (Westinghouse), dated May 17, 1988. The PHOENIX-P SER does not identify any conditions, restrictions, or limitations that need to be addressed for application to MPS3.

2.8.5.0.11 References

1. ANS N18.2-1973, Nuclear Safety Criteria for the Design of Stationary PWRs, American Nuclear Society.
2. WCAP-11397-P-A, Revised Thermal Design Procedure, A. J. Friedland and S. Ray, April 1989.
3. WCAP-8745-P-A, Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions, S. L. Ellenberger, et al., September 1986.
4. ANSI/ANS-5.1-1979, American National Standard for Decay Heat Power In Light Water Reactors, August 29, 1979.
5. WCAP-7908-A, FACTRAN – A FORTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod, H. G. Hargrove, December 1989.
6. WCAP-15063-P-A Revision 1, with Errata, Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), J. P. Foster and S. Sidener, July 2000.
7. WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999.
8. WCAP-9272-P-A, Westinghouse Reload Safety Evaluation Methodology, S. L. Davidson (Ed.), July 1985.
9. WCAP-7907-P-A, LOFTRAN Code Description, T. W. T. Burnett, et al., April 1984.
10. WCAP-7979-P-A, TWINKLE – A Multi-Dimensional Neutron Kinetics Computer Code, D. H. Risher, Jr. and R. F. Barry, January 1975.
11. WCAP-10965-P-A, ANC: A Westinghouse Advanced Nodal Computer Code, Y. S. Liu, et al., September 1986.
12. WCAP-14565-P-A, VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Y. X. Sung, et al., October 1999.
13. WCAP-15025-P-A, Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids, L. D. Smith, III, et al., April 1999.
14. Letter from D.S. Collins (NRC) to J.A. Gresham (Westinghouse), Subject: “Modified WRB-2 Correlation WRB-2M for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids,” February 3, 2006.
15. WCAP-11596-P-A, Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, T. Q. Nguyen, et al., June 1988.

Table 2.8.5.0-1
Nuclear Steam Supply System Power Ratings

	MWt
NSSS thermal power output (0 MWt Pump Heat)	3650
NSSS thermal power output (0 MWt Pump Heat)	3723 **
NSSS thermal power output (16 * MWt nominal Pump Heat)	3666
NSSS thermal power output (16 * MWt nominal Pump Heat)	3739 **

* Nominal four-loop pump heat. Some transients modeled a maximum pump heat of 20 MWt as noted in Table 2.8.5.0-2.

** Includes 2.0% power uncertainty.

Table 2.8.5.0-2
Summary of Initial Conditions and Computer Codes Used

FSAR Section	Faults	Computer Codes Utilized	Reactivity Coefficients Assumed			Initial NSSS Thermal Power Output Assumed (MWt)
			Moderator Temperature (pcm/°F)	Moderator Density (Δk/gm/cc)	Doppler	
15.1	Increase in heat removal by the secondary system					
	Feedwater system malfunctions that result in an increase in feedwater flow	RETRAN VIPRE	-	0.50 for Full Power; Function of moderator density for HZP (see Section 2.8.5.1.1.2.2)	Lower (see Fig. 2.8.5.0-2) for Full Power; For HZP see Section 2.8.5.1.1.2.2	0 [a] & 3666 [b]
	Excessive increase in secondary steam flow	N/A	See Section 2.8.5.1.1.2.3	See Section 2.8.5.1.1.2.3	See Section 2.8.5.1.1.2.3	3666 [b]
	Inadvertent opening of a steam generator relief or safety valve	Results bounded by steam system piping failure				
	Steam system piping failure	RETRAN VIPRE	-	Function of moderator density (see Section 2.8.5.1.2)	See Section 2.8.5.1.2	0 [a] (Subcritical)
15.2	Decrease in heat removal by the secondary system					

Table 2.8.5.0-2
Summary of Initial Conditions and Computer Codes Used

FSAR Section	Faults	Computer Codes Utilized	Reactivity Coefficients Assumed: Moderator Temperature (pcm/°F)	Reactivity Coefficients Assumed: Moderator Density (Δk/gm/cc)	Reactivity Coefficients Assumed: Doppler	Initial NSSS Thermal Power Output Assumed (MWt)
	Loss of external electrical load and/or turbine trip	RETRAN	0	-	Lower (see Fig. 2.8.5.0-2)	3666 [b] (DNB case) & 3739 [a] (peak pressure cases)
	Loss of non-emergency AC power to the station auxiliaries	Results bounded by loss of normal feedwater				
	Loss of normal feedwater flow	RETRAN	0	-	Upper (see Fig. 2.8.5.0-2)	3739 [a, c]
	Feedwater system pipe break	RETRAN	0	0.45	Upper and lower (see Fig. 2.8.5.0-2)	3739 [a, c]
15.3	Decrease in reactor coolant system flow rate					
	Partial and complete loss of forced reactor coolant flow	RETRAN VIPRE	0	--	Upper (see Fig. 2.8.5.0-2)	3666 [b]
	Reactor coolant pump shaft seizure (locked rotor)	RETRAN VIPRE	0	--	Upper (see Fig. 2.8.5.0-2)	3666 [b] (rods in DNB case) & 3739 [a] (pressure and temperature case)

Table 2.8.5.0-2
Summary of Initial Conditions and Computer Codes Used

FSAR Section	Faults	Computer Codes Utilized	Reactivity Coefficients Assumed			Initial NSSS Thermal Power Output Assumed (MWt)
			Moderator Temperature (pcm/°F)	Moderator Density (Δk/gm/cc)	Doppler	
15.4	Reactivity and power distribution anomalies					
	Uncontrolled RCCA bank withdrawal from a subcritical or lower power startup condition	TWINKLE FACTRAN VIPRE	5.0	--	Consistent with Doppler defect of -0.900%Δk	0 [a] (Subcritical)
	Uncontrolled RCCA bank withdrawal at power	RETRAN VIPRE	5.0 (part power cases) & 0 (full power case)	0.5	Upper and lower (see Fig. 2.8.5.0-2)	367, 2200, & 3666 [b]
	RCCA misalignment	LOFTRAN ANC VIPRE	-	-	-	3666 [b]
	Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant	N/A	N/A	N/A	N/A	N/A
	Inadvertent loading and operation of a fuel assembly in an improper position	LEOPAR D TURTLE		N/A		N/A

Table 2.8.5.0-2
Summary of Initial Conditions and Computer Codes Used

FSAR Section	Faults	Computer Codes Utilized	Reactivity Coefficients Assumed			Initial NSSS Thermal Power Output Assumed (MWt)
			Moderator Temperature (pcm/°F)	Moderator Density (Δk/gm/cc)	Doppler	
	Spectrum of RCCA ejection accidents	TWINKLE FACTRAN	Refer to Section 2.8.5.4.6, min. and max. feed-back	-	Consistent with Doppler defect of -0.900%Δk	0 & 3650 [a]
15.5	Increase in reactor coolant inventory					
	Inadvertent operation of the ECCS during power operation	RETRAN	--	0.5	Upper (see Fig. 2.8.5.0-2)	3739 [a, c]
	CVCS malfunction that results in an increase in the reactor coolant inventory	RETRAN	--	0.5	Upper (see Fig. 2.8.5.0-2)	3739 [a, c]
15.6	Decrease in reactor coolant inventory					
	Inadvertent opening of a pressurizer safety or relief valve	RETRAN	0	--	Lower (see Fig. 2.8.5.0-2)	3666 [b]
	Steam generator tube failure	LOFTTR2	0	--	Upper (see Fig. 2.8.5.0-2)	3739 [a]

Table 2.8.5.0-2
Summary of Initial Conditions and Computer Codes Used

FSAR Section	Faults	Computer Codes Utilized	Reactivity Coefficients Assumed: Moderator Temperature (pcm/°F)	Reactivity Coefficients Assumed: Moderator Density (Δk/gm/cc)	Reactivity Coefficients Assumed: Doppler	Initial NSSS Thermal Power Output Assumed (MWt)
	Loss-of-coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary	ASTRUM NOTRUMP	Refer to Section 2.8.5.6.3		Refer to Section 2.8.5.6.3	3650 3723

a. STDP with Thermal Design Flow
b. RTDP with Minimum Measured Flow
c. A maximum pump heat of 20 MWt was modeled in the cases with offsite power available.

Table 2.8.5.0-3
Plant Initial Condition Assumptions

Parameter	RTDP	Non-RTDP	Notes
NSSS Power (MWt)	3666.0	3739.0	1
Nominal Total Net RCP Heat (MWt)	16.0	16.0	1, 2, 3
Maximum Full-Power Vessel T_{avg} (°F)	589.5	589.5 ± 4.0	1
Minimum Full-Power Vessel T_{avg} (°F)	571.5	571.5 ± 4.0	1
No-Load RCS Temperature (°F)	557.0	557.0	1
Pressurizer Pressure (psia)	2250	2250 ± 50	1
Steam Flow (lbm/hr)	see Note 4	see Note 4	4
Steam Pressure (psia)	see Note 4	see Note 4	4
Maximum Full-Power Feedwater Temperature (°F)	445.3	445.3	1
Minimum Full-Power Feedwater Temperature (°F)	390.0	390.0	1
Pressurizer Water Level (% span)	see Note 5	see Note 5	5
Steam Generator Water Level (% NRS)	see Note 6	see Note 6	6

Notes:
1. See Table 1-1 in Section 1.0 of Licensing Report.
2. Total RCP heat input minus RCS thermal losses.
3. A maximum net RCP heat of 20 MWt was conservatively assumed in some non-RTDP analyses, e.g., loss-of-normal feedwater.
4. The nominal steam flow rate and steam pressure depend on other nominal conditions. See Table 1-1 of Licensing Report.
5. The nominal/programmed pressurizer water level varied linearly from 28% of span at the no-load T_{avg} of 557°F to 64% of span for T_{avg} 587.0°F. An uncertainty of ±7.6% of span was applied when conservative.
6. The programmed steam generator water level modeled in the analyses was a constant 50% narrow range span (NRS) for all power levels. An uncertainty of ±12% NRS was applied when conservative.

Table 2.8.5.0-4
Core Kinetics Parameters and Reactivity Feedback Coefficients

Parameter	Beginning of Cycle (Minimum Feedback)	End of Cycle (Maximum Feedback)
MTC, pcm/°F	5.0 (< 70% RTP) 0.0 (≥ 70% RTP)	N/A
Moderator Density Coefficient[1], Δk/(g/cc)	N/A	0.5
Doppler Temperature Coefficient, pcm/°F	-0.90	-3.20
Doppler-Only Power Coefficient, pcm/%power (Q = power in %)	-9.55 + 0.035Q	-19.4 + 0.068Q
Delayed Neutron Fraction[2]	0.0075 (maximum)	0.0040 (minimum)
Minimum Doppler Power Defect, pcm		
– RCCA Ejection	900	900
– RCCA Withdrawal from Subcritical	900	N/A

Note:
1. For the Feedline Break event, a maximum moderator density coefficient of 0.45 Δk/(g/cc) was modeled.
2. For the RCCA Ejection event at beginning of cycle, a minimum delayed neutron fraction of 0.0050 was modeled.

Table 2.8.5.0-5
Trip Point and Time Delays to Trip Assumed in Accident Analyses

Trip Function	Limiting Trip Point Assumed in Analyses [(1)]	Time Delay (Seconds)
Power range high neutron flux, high setting	116.5%	0.5
Power range high neutron flux, low setting	35%	0.5
Overtemperature ΔT	Variable; see Table 2.8.5.0-6 and Figure 2.8.5.0-1	7.0 [(2)]
Overpower ΔT	Variable; see Table 2.8.5.0-6 and Figure 2.8.5.0-1	7.0 [(2)]
High pressurizer pressure	2410 psig	2.0
Low pressurizer pressure	1845 psig	2.0
Low reactor coolant flow (from loop flow detectors)	85% loop flow	1.0
Reactor coolant pump underspeed	92% nominal	0.6
Turbine trip	Not applicable	1.5 [(3)]
Low-Low steam generator water level	0% of narrow range level span (both feed line break and loss of normal feedwater/loss of off-site power)	2.0

Table 2.8.5.0-5
Trip Point and Time Delays to Trip Assumed in Accident Analyses

Trip Function	Limiting Trip Point Assumed in Analyses (1)	Time Delay (Seconds)
High-high steam generator level trip of the feedwater pumps and closure of feedwater system valves, and turbine trip	100% of narrow range level span	2.5 (4) 7.0 (5)

1. Tabulated values conservatively bound technical specification values with uncertainties. Refer to Section 2.8.5.6.2 for SGTR trip point assumptions.
2. Total time delay from time the temperature difference in the coolant loop exceeds the trip setpoint until the RCCAs are free to fall. Delay includes the response characteristics of the RTD/thermowell/scoop configuration, electronic delays, trip breaker opening delays, and gripper opening delays.
3. Direct reactor trip following turbine trip not credited to meet the acceptance criteria.
4. From time setpoint is reached to turbine trip.
5. From time setpoint is reached to feedwater isolation.

Table 2.8.5.0-6
Overtemperature and Overpower ΔT Setpoints

Allowable Full-Power T_{avg} Range	571.5° to 589.5°F
K_1 (safety analysis value)	1.37
K_2	0.025/°F
K_3	0.00113/psi
K_4 (safety analysis value)	1.173
K_6	0.0015/°F (1)
T′	571.5° to 589.5°F (2)
P′	2250 psia
f(ΔI) Deadband	-18% ΔI to +10% ΔI
f(ΔI) Negative Gain	-3.75%/%ΔI
f(ΔI) Positive Gain	+2.14%/%ΔI

Notes:
1. K6 = 0.0015/°F is valid for T_{avg} > T′. For T_{avg} T′, K6 = 0.0/°F.
2. Value to be set equal to or less than the full power operating T_{avg} chosen.

Table 2.8.5.0-7
Plant Systems and Equipment Required for the Mitigation of Transient and Accident Conditions

FSAR Section	Incident	Reactor Trip Functions	ES Actuation Functions	Other Equipment	ESF Equipment
15.1	Increase in heat removal by the secondary system				
	Feedwater system malfunctions	Power range high flux, reactor trip caused by turbine trip on high-high steam generator level, manual, overtemperature ΔT, overpower ΔT, turbine trip	High-High steam generator level-produced feedwater isolation and turbine trip, SI initiated by low steam line pressure or low pressurizer pressure will produce feedwater isolation, manual	Feedwater isolation valves	---
	Excessive increase in secondary steam flow	Power range high flux, overtemperature ΔT, overpower ΔT, manual, low pressurizer pressure	N/A	Pressurizer self-actuated safety valves, steam generator safety valves	---

Table 2.8.5.0-7
Plant Systems and Equipment Required for the Mitigation of Transient and Accident Conditions

FSAR Section	Incident	Reactor Trip Functions	ES Actuation Functions	Other Equipment	ESF Equipment
	Inadvertent opening of a steam generator relief or safety valve	Low pressurizer pressure, manual, SIS, power range high flux trip, overpower ΔT	Low pressurizer pressure, low compensated steam line pressure, high negative steam pressure rate, steam generator low-low water level, manual	Feedwater isolation valves, steam line isolation valves	Auxiliary feedwater system, ECCS
	Steam system piping failure	SIS, low pressurizer pressure, power range high flux trip, overpower ΔT, steam generator low-low water level, manual	Low pressurizer pressure, low compensated steam line pressure, high negative steam pressure rate, hi-1 containment pressure, steam generator low-low water level, manual	Feedwater isolation valves, steam line isolation valves	Auxiliary feedwater system, ECCS
15.2	Decrease in heat removal by the secondary system				
	Loss of external electrical load/turbine trip	High pressurizer pressure, overtemperature ΔT, overpower ΔT, steam generator low-low level, manual	N/A	Pressurizer safety valves, steam generator safety valves	---

Table 2.8.5.0-7
Plant Systems and Equipment Required for the Mitigation of Transient and Accident Conditions

FSAR Section	Incident	Reactor Trip Functions	ES Actuation Functions	Other Equipment	ESF Equipment
	Loss of non-emergency AC power to the station auxiliaries	Steam generator low-low level, turbine trip, low RCS flow, manual	Steam generator low-low level, manual, loss of offsite power	Steam generator safety valves	Auxiliary feedwater system
	Loss of normal feedwater flow	Steam generator low-low level, overtemperature ΔT, high pressurizer pressure, manual	Steam generator low-low level, manual	Steam generator safety valves	Auxiliary feedwater system
	Feedwater system pipe break	Steam generator low-low level, high pressurizer pressure, overtemperature ΔT, SIS, manual	Hi-1 containment pressure, steam generator low-low water level, low compensated steam line pressure, low pressurizer pressure, manual	Steam line isolation valves, feedline isolation, pressurizer self-actuated safety valves, steam generator safety valves	Auxiliary feedwater system, ECCS
15.3	Decrease in reactor coolant system flow rate				
	Partial loss of forced reactor coolant flow	Low flow, manual	N/A	Steam generator safety valves	---
	Complete loss of forced reactor coolant flow	Low flow, RCP underspeed, manual	N/A	Steam generator safety valves	---

Table 2.8.5.0-7
Plant Systems and Equipment Required for the Mitigation of Transient and Accident Conditions

FSAR Section	Incident	Reactor Trip Functions	ES Actuation Functions	Other Equipment	ESF Equipment
	Reactor coolant pump shaft seizure (locked rotor)	Low flow, manual	N/A	Pressurizer safety valves, steam generator safety valves	---
15.4	Reactivity and power distribution anomalies				
	Uncontrolled rod cluster control assembly bank withdrawal from a subcritical or lower power startup condition See Note 1	Power range high flux (low and high setpoints), source range high flux, intermediate range high flux, power range neutron flux high positive flux rate, manual	N/A	---	---
	Uncontrolled rod cluster control assembly bank withdrawal at power	Power range high flux, high positive neutron flux rate, high pressurizer water level, overtemperature ΔT, overpower ΔT, high pressurizer pressure, manual	N/A	Pressurizer safety valves, steam generator safety valves	---
	Rod cluster control assembly misalignment	Overtemperature ΔT, overpower ΔT, low pressurizer pressure, manual	N/A	---	---

Table 2.8.5.0-7
Plant Systems and Equipment Required for the Mitigation of Transient and Accident Conditions

FSAR Section	Incident	Reactor Trip Functions	ES Actuation Functions	Other Equipment	ESF Equipment
	Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant	Source range high flux, power range high flux (high and low setpoint), overtemperature ΔT, manual	N/A	Low insertion limit annunciators shutdown margin monitors	---
	Spectrum of rod cluster control assembly ejection accidents	Power range high flux (high and low setpoint), high positive flux rate, manual	N/A	---	---
15.5	Increase in reactor coolant inventory				
	Inadvertent operation of the ECCS during power operation	Manual, safety injection trip	N/A	Pressurizer power operated relief valves, low pressurizer pressure cold leg injection permissive signal	---
	CVCS malfunction that results in an increase in the reactor coolant inventory	Manual	N/A	Pressurizer power operated relief valves	---

Table 2.8.5.0-7
Plant Systems and Equipment Required for the Mitigation of Transient and Accident Conditions

FSAR Section	Incident	Reactor Trip Functions	ES Actuation Functions	Other Equipment	ESF Equipment
15.6	Decrease in reactor coolant inventory				
	Inadvertent opening of a pressurizer safety or relief valve	Pressurizer low pressure, overtemperature ΔT, manual	N/A	---	---
	Steam generator tube failure	Low pressurizer pressure, overtemperature ΔT, manual	Low pressurizer pressure, steam generator low-low water level	Service water system, component cooling water system, Steam Generator Water Level Control (SGWLC), steam generator safety and/or relief valves, main steam isolation valves, emergency diesel generator, pressurizer power operated relief valves or pressurizer spray	Emergency core cooling system, auxiliary feedwater system

Table 2.8.5.0-7
Plant Systems and Equipment Required for the Mitigation of Transient and Accident Conditions

FSAR Section	Incident	Reactor Trip Functions	ES Actuation Functions	Other Equipment	ESF Equipment
	Loss-of-coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary	Low pressurizer pressure, manual	Low pressurizer pressure, Hi-1 & Hi-3 containment pressure	Service water system, component cooling water system, steam generator safety and/or relief valves, emergency diesel generator	Emergency core cooling system, auxiliary feedwater system, containment heat removal system

1. Administrative controls have been implemented to preclude an uncontrolled rod/bank withdrawal from a subcritical condition when plant conditions are not bounded by safety analysis assumptions.

N/A = ESF actuation functions are not applicable for these accidents.

Figure 2.8.5.0-1
Illustration of Overtemperature and Overpower ∆T Protection

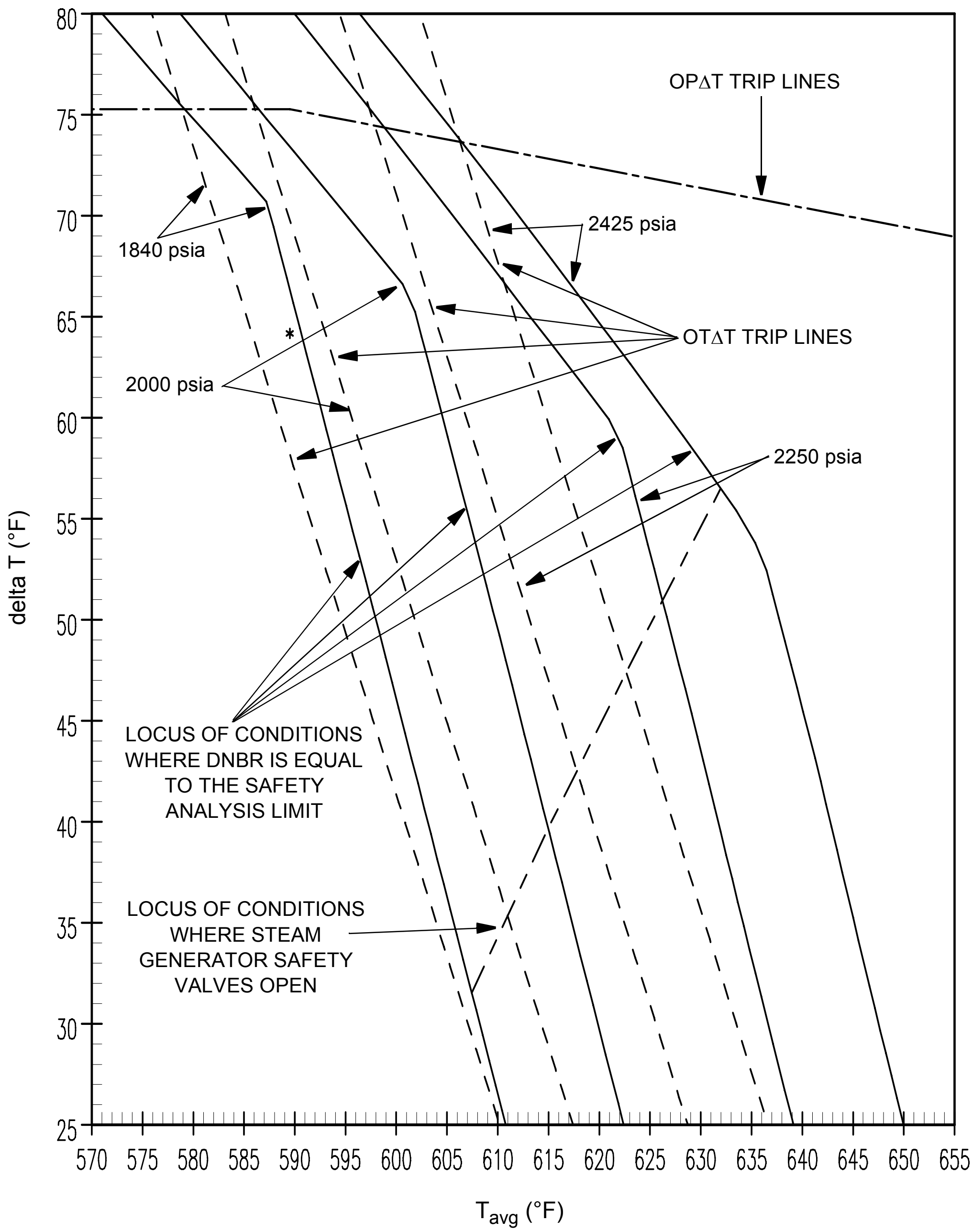


Figure 2.8.5.0-2
Doppler Power Coefficient Used in Accident Analysis

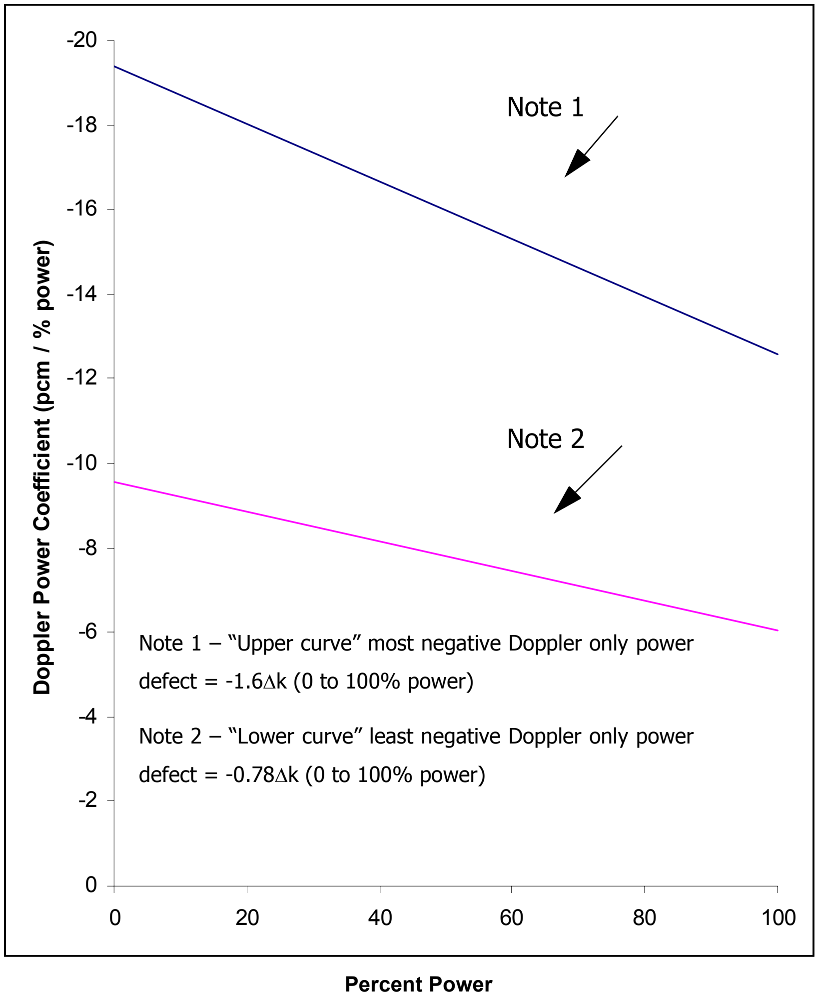


Figure 2.8.5.0-3
RCCA Position Versus Time to Dashpot

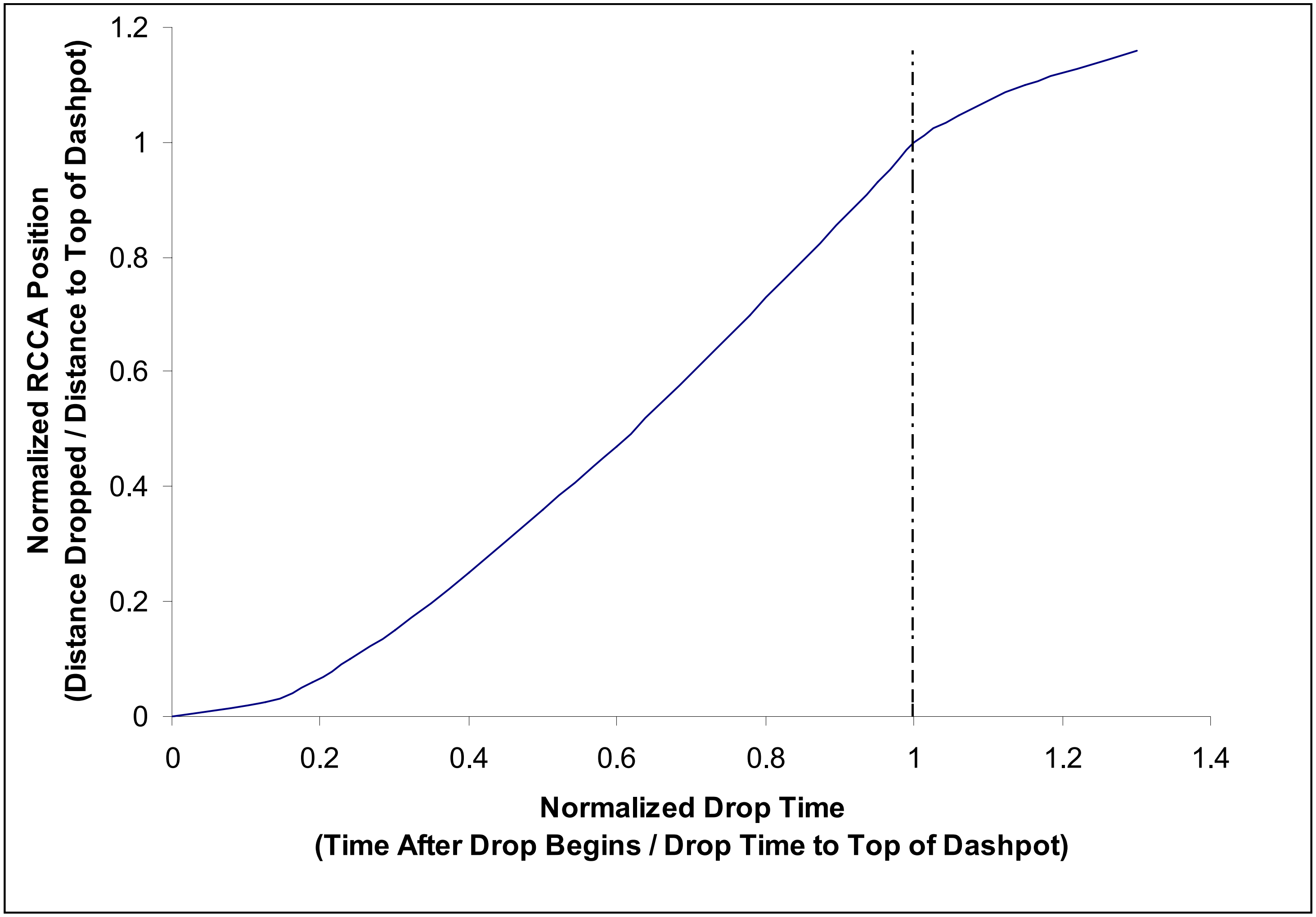


Figure 2.8.5.0-4
Normalized Rod Worth Versus Fraction Inserted

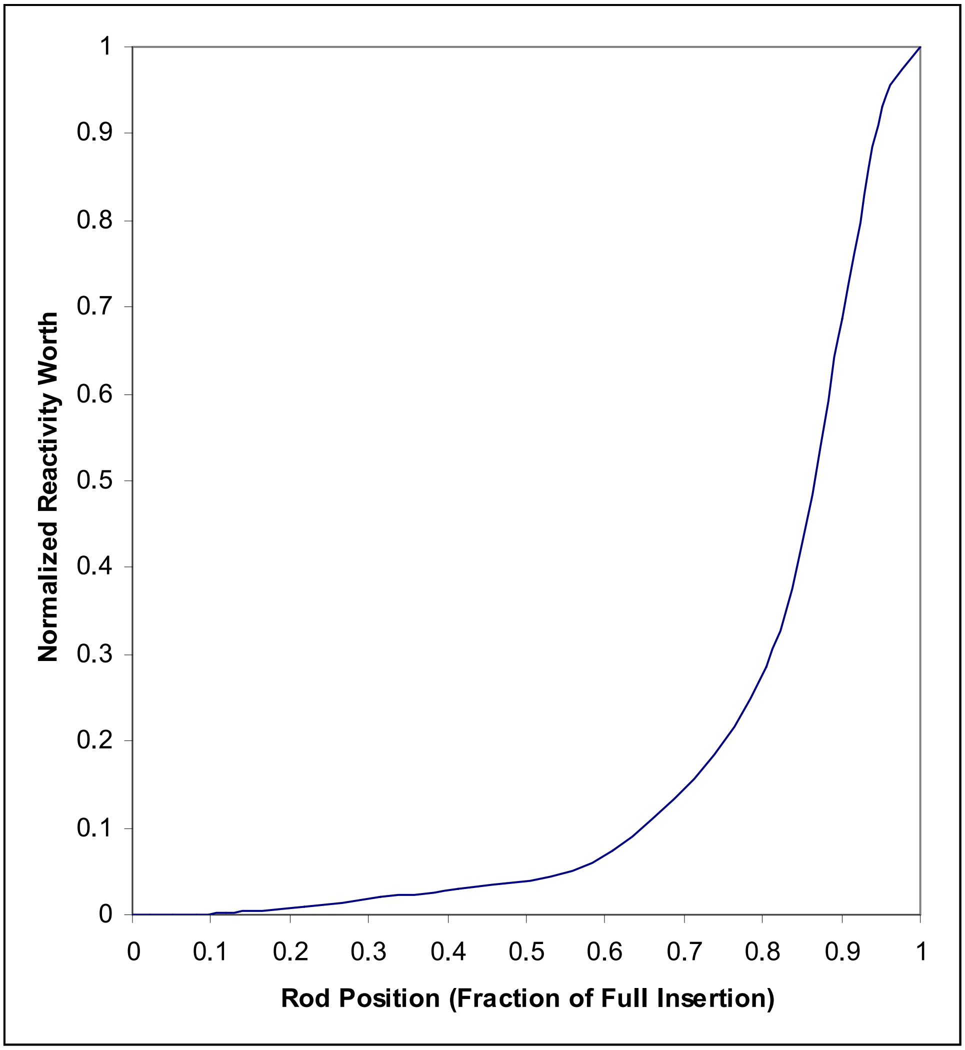
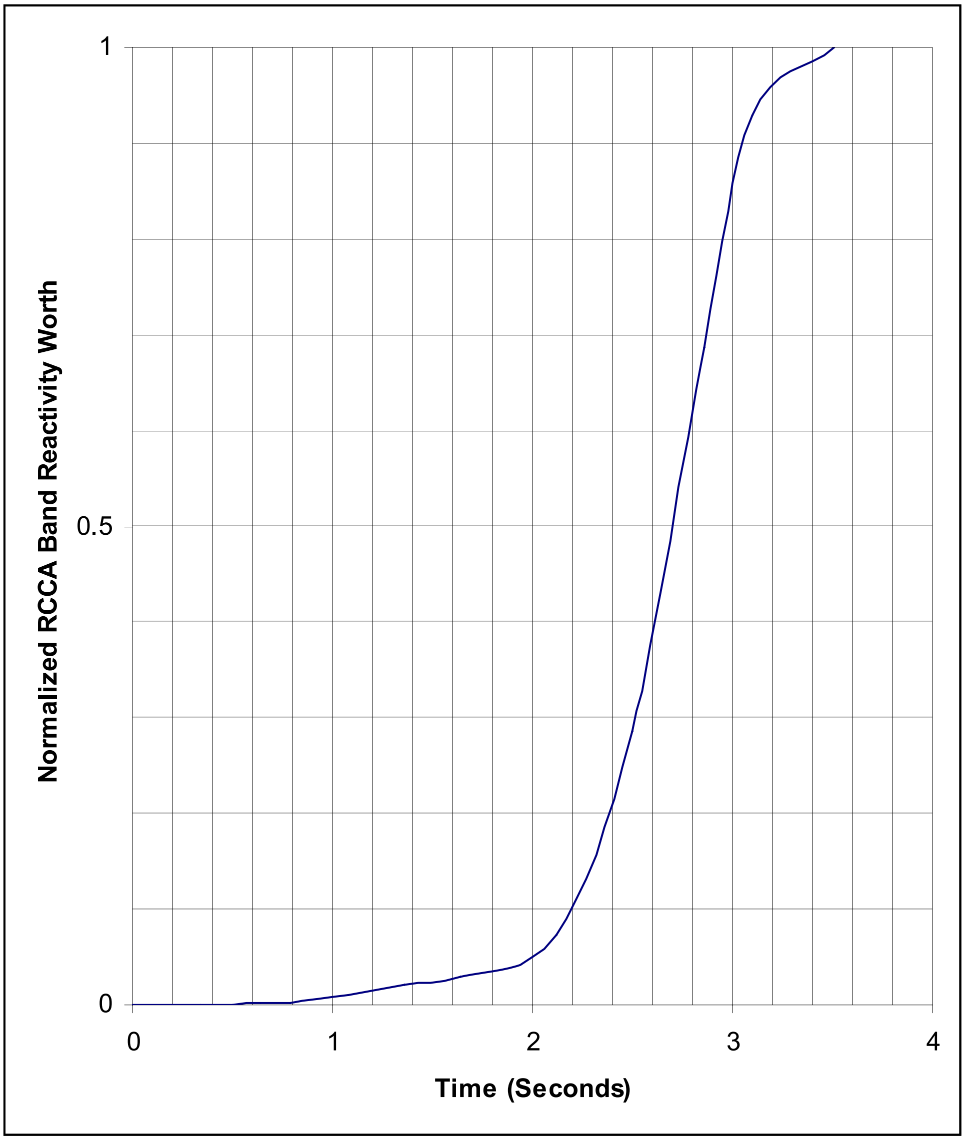


Figure 2.8.5.0-5
Normalized RCCA Bank Reactivity Worth Versus Drop Time



2.8.5.1 Increase in Heat Removal by the Secondary System

2.8.5.1.1 Decrease In Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

2.8.5.1.1.1 Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. Any unplanned power level increase can result in fuel damage or excessive reactor system pressure. Reactor protection and safety systems are actuated to mitigate the transient.

The DNC review covered:

- The postulated initial core and reactor conditions
- The methods of thermal-hydraulic analyses
- The sequence of events
- The assumed reactions of reactor system components
- The functional and operational characteristics of the reactor protection system
- The operator actions
- The results of the transient analyses

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences (AOOs)
- GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation
- GDC-20, insofar as it requires that the reactor protection system be designed to automatically initiate the operation of appropriate systems, including reactivity control systems, to ensure that SAFDLs are not exceeded during any condition of normal operation, including AOOs
- GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded

Specific review criteria are contained in SRP Section 15.1.1-4, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 15.1.1-4, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to:

- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant clean up system to mitigate, and are consistent with plant design bases.

2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

   Note that the term "fuel damage" as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

   FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protection systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-15, Reactor Coolant System Design, is described in FSAR Section 3.1.2.15.

  The design pressure and temperature for each component in the reactor coolant and associated auxiliary, control and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

  Additionally, RCPB components achieve a large margin of safety by the use of proven ASME materials and design codes; the use of proven fabrication techniques; nondestructive shop testing; and integrated hydrostatic testing of assembled components. FSAR Chapter 5 discusses the RCS design.

- GDC-20, Protection System Functions, is described in FSAR Section 3.1.2.20.

  A fully automatic protection system, with appropriate redundant channels, is provided to cope with transients where insufficient time is available for manual corrective action. The design basis for all protection systems is IEEE Standard 279-1971 and IEEE Standard 379-1972. The reactor protection system automatically initiates a reactor trip when any variable exceeds the normal operating range. Setpoints are designed to provide an envelope of safe operating conditions with adequate margin for uncertainties to ensure that fuel design limits are not exceeded.

Reactor trip is initiated by removing power to the rod drive mechanisms of all of the full length rod cluster control assemblies. This causes the rods to insert by gravity, which rapidly reduces reactor power output. The response and adequacy of the protection system have been verified by analysis of expected transients.

The ESF actuation system automatically initiates emergency core cooling, and other safeguards functions, by sensing accident conditions using redundant analog channels measuring diverse variables. Manual actuation of safeguards equipment may be performed where ample time is available for operator action. The ESF actuation system automatically trips the reactor on manual or automatic SIS generation.

- GDC-26, Reactor Coolant System Redundancy and Capability, is described in FSAR Section 3.1.2.26.

  Two reactivity control systems are provided. They are the RCCAs and chemical shim (boric acid). The RCCAs are inserted into the core by the force of gravity.

  During operation, the shutdown rod banks are fully withdrawn. The rod control system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specific fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses, and the most reactive rod cluster is assumed to be in the fully withdrawn position.

  The CVCS maintains the reactor in the cold shutdown state independent of the position of the control rods. It can compensate for xenon burnout transients.

  FSAR Chapter 4 presents details of the construction of the RCCAs. FSAR Chapter 7 discusses their operation. FSAR Chapter 9 describes the means of controlling boric acid concentration. FSAR Chapter 15 includes performance analyses under accident conditions.

FSAR Sections 15.1.1, 15.1.2, 15.1.3, and 15.1.4 summarize the analyses of feedwater system malfunctions that result in a decrease in feedwater temperature, feedwater system malfunctions that result in an increase in feedwater flow, excessive increase in secondary steam flow, and inadvertent opening of a steam generator relief or safety valve, respectively. These events are classified as Condition II events.

Decrease in Feedwater Temperature

FSAR Section 15.1.1.3 states that the decrease in feedwater temperature transient is less severe than the increase in secondary steam flow event (FSAR Section 15.1.3). Based on results presented in FSAR Section 15.1.3, the applicable acceptance criteria for the decrease in feedwater temperature event have been met.

Increase in Feedwater Flow

FSAR Section 15.1.2.2 and Table 15.0-2 state that the transient is analyzed utilizing the LOFTRAN (WCAP-7907-P-A) and THINC codes. LOFTRAN computes pertinent plant variables including temperatures, pressures, and power level; and THINC determines if DNB occurs.

Section 15.1.2.3 states that, for excessive feedwater addition events, the results show that the DNBRs encountered are above the limiting values at all times. Therefore, the DNBR design basis as described in FSAR Section 4.4 is met.

Excessive Increase in Secondary Steam Flow

Steam flow increases greater than 10 percent are analyzed in FSAR Sections 15.1.4 and 15.1.5.

FSAR Table 15.0-2 and Section 15.1.3.2 state that the transient is analyzed utilizing the LOFTRAN code to compute pertinent plant variables including temperatures, pressures, and power level.

This 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.

FSAR Section 15.1.3.3 concludes that the DNBR remains above the safety analysis limit for a 10 percent step load increase. The design basis for DNBR as described in FSAR Section 4.4 is met. The plant reaches a stabilized condition rapidly following the load increase.

Inadvertent Opening of a Steam Generator Relief or Safety Valve

FSAR Section 15.1.4.1 states that the most severe core conditions resulting from an accidental depressurization of the main steam system are associated with an inadvertent opening, with failure to close, of the largest of any single steam dump, relief, or safety valve. The analyses performed assuming a rupture of a main steam line are given in FSAR Section 15.1.5.

The steam release as a consequence of this accident results in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity.

FSAR Section 15.1.4.2 and Table 15.0-2 state that the transient is analyzed utilizing the LOFTRAN code to compute pertinent plant variables including temperatures, pressures, and power level.

FSAR Section 15.1.4.3 concludes that the minimum DNBR remains well above the limiting value for an accidental depressurization of the main steam system. In addition, no system design limits are exceeded.

Westinghouse NSALs 02-3 Rev. 01; 02-4, Rev. 0; and 02-5 Rev 01 identified potential non-conservative errors in SG level measurement due to the pressure drop across the SG mid deck plate; potential impacts on the SG level reactor trip setpoints; and potential impacts to SG water level control system uncertainties utilized as initial condition assumptions for SG water level related safety analyses. DNC implemented modifications to the MPS3 narrow range SG level measurement instrument loops during 3R11 (April, 2007) to address changes in instrument uncertainties for level control and setpoints used for SG low-low level reactor trip.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.1.1.2 Technical Evaluation

2.8.5.1.1.2.1 Decrease in Feedwater Temperature

2.8.5.1.1.2.1.1 Introduction

Reductions in feedwater temperature cause an increase in core power by decreasing reactor coolant temperature. A reduction in feedwater temperature may be caused by the accidental opening of a feedwater bypass valve that diverts flow around a portion of the feedwater heaters and trip of the heater drain pumps as well as loss of extraction steam to the high pressure feedwater heater. For this event, there is a sudden reduction in feedwater inlet temperature to the steam generators.

At power, this increased subcooling creates a greater load demand on the RCS. With the plant at no-load conditions the addition of cold feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator coefficient of reactivity. However, the rate of energy change is reduced as load and feedwater flow decrease, so the no-load transient is less severe than the full power case.

2.8.5.1.1.2.1.2 Description of Analyses and Evaluation

The opening of a low-pressure feedwater heater bypass valve causes a reduction in feedwater temperature that increases the thermal load on the primary system. The increased thermal load due to the opening of the condensate bypass valve results in a transient similar to (but of a reduced magnitude from) the increase in secondary steam flow event conditions described in Section 2.8.5.1.1.2.3 (Excessive Load Increase). Thus, the feedwater temperature reduction transient is bounded by an increase in secondary steam flow event. Since the increase in steam flow is analyzed to Condition II acceptance criteria, no transient results are presented here, as no explicit analysis is performed for the decrease in feedwater temperature case.

2.8.5.1.1.2.2 Increase in Feedwater Flow

2.8.5.1.1.2.2.1 Introduction

Addition of excessive feedwater causes an increase in core power by decreasing reactor coolant temperature. An example of excessive feedwater flow would be a full opening of a feedwater control valve due to a feedwater control system malfunction or an operator error. At power, this excess flow causes a greater load demand on the RCS due to increased subcooling in the steam generator. With the plant at no-load conditions, the addition of an excess of feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator coefficient of reactivity.

2.8.5.1.1.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The feedwater system malfunction event is analyzed to confirm that the minimum DNBR remains greater than the limit. Thus, the analysis uses the following key modeling characteristics:

- The Revised Thermal Design Procedure (RTDP) (Reference 1) is employed for the cases initiated from full-power. Initial reactor power, RCS pressure, and RCS temperature are assumed to be at their nominal values consistent with steady-state full power operation. Minimum measured flow (MMF) is modeled. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 1. The initial conditions for the event are summarized in Table 2.8.5.0-1.
- The analyses are performed at the uprated NSSS power level of 3666 MWt.
- For the feedwater control valve failure at full-power conditions that results in an increase in feedwater flow to one steam generator, one feedwater control valve is assumed to malfunction resulting in a step increase to 234 percent of the nominal full power feedwater flow to one steam generator.
- For the feedwater control malfunction at full-power conditions that results in an increase in feedwater flow to all four steam generators, the feedwater control valve malfunction is assumed to result in a step increase to 234 percent of the nominal full power feedwater flow to all four steam generators.
- The increase in feedwater flow rate results in a decrease in the feedwater temperature due to the reduced efficiency of the feedwater heaters. For the full-power cases, a 25 Btu/lbm decrease in the feedwater enthalpy is conservatively assumed to occur coincident with the feedwater flow increase.
- For the feedwater malfunction accident at no-load conditions that results in an increase in feedwater flow to one steam generator, one feedwater control valve is assumed to malfunction resulting in a step increase to 250 percent of the full power nominal flow to one steam generator.
- For the feedwater malfunction accident at no-load conditions that results in an increase in feedwater flow to all four steam generators, the feedwater control valve malfunction is assumed to result in a step increase to 250 percent of the full power nominal flow to all four steam generators.
- For the cases initiated at zero-power, initial reactor power, RCS pressure, and RCS temperature are assumed to be at levels corresponding to no-load conditions. Thermal design flow is modeled. In addition, the reactor is assumed to be at the minimum shutdown margin condition of 1.3 percentΔk.
- For the full-power cases, an initial water level of nominal-minus-uncertainty in all four steam generators is modeled, while an initial level at nominal level is modeled for the zero-power cases.

- Pressurizer sprays and power-operated relief valves (PORVs) are modeled to reduce RCS pressure resulting in a conservative evaluation of the margin to the DNBR limit.
- Cases are analyzed with and without automatic rod insertion for the full-power cases.
- For cases at zero-load conditions, the initial feedwater temperature is assumed to be 100°F.
- No credit is taken for the heat capacity of the RCS and steam generator metal mass in attenuating the resulting plant cooldown.

Based on its frequency of occurrence, the feedwater system malfunction event is considered a Condition II event as defined by the American Nuclear Society (ANS). As such, the applicable acceptance criteria for this incident are:

- Pressure in the RCS and Main Steam System (MSS) should be maintained below 110 percent of the design pressures.
- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains greater than the 95/95 DNBR limit in the limiting fuel rods.
- An accident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

The primary acceptance criterion used in this analysis is that the minimum DNBR remains greater than the safety analysis limit. The event does not challenge the primary and secondary side pressure limits since the increased heat removal tends to cool the RCS.

For failures that result in an increase in feedwater flow, there is also the possibility of steam generator overfill and resulting damage to the steam turbine and steam piping due to excessive moisture carryover. However, steam generator overfill is prevented via automatic feedwater isolation from the high steam generator water level trip.

2.8.5.1.1.2.2.3 Description of Analyses and Evaluations

The excessive heat removal due to a feedwater system malfunction transient was analyzed with the RETRAN (Reference 2) and VIPRE (Reference 3) computer codes. The RETRAN code simulates a multi-loop RCS, core neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray and heaters, steam generators, and main steam safety valves (MSSVs), and computes pertinent plant variables including temperatures, pressures, and power level. The VIPRE code is used to determine if the DNBR remains above the DNBR limit.

These computer codes are different than those used for the current licensing basis analysis where the LOFTRAN (WCAP-7907-P-A) and THINC codes are used. RETRAN and VIPRE have been approved by the NRC for the analysis of excessive feedwater flow transients (Reference 2 and 3). Section 2.8.5.0 of this report contains a discussion of the applicability of these computer codes and compliance with the SER limitations for these codes for Millstone 3.

The excessive feedwater flow event assumes an accidental opening of one or more feedwater control valves with the reactor at both full and zero power conditions with both automatic and manual rod control, where applicable. Both the automatic and manual rod control cases assume a conservatively large moderator density coefficient characteristic at EOL conditions. Table 2.8.5.1.1.2.2-1 summarizes the analyzed cases.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the excessive feedwater flow analysis. As stated in Section 2.8.5.1.1.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.1.1.2.2.4 Results

Considering the excessive feedwater flow full-power cases with and without automatic rod control and presenting the more limiting results demonstrates that the rod control system is not required to function for this event. A turbine trip, which results in a reactor trip, is actuated when the steam generator water level in the affected steam generator reaches the high-high water level setpoint. A comparison of the multiple-loop (failure of all four feedwater control valves) and single-loop (failure of a single feedwater control valve) cases demonstrates that the multiple-loop failure case is more limiting. The HFP results presented are from the case assuming multiple-loop failure with the automatic rod control system not operable (the most limiting case).

The case initiated at hot zero power conditions is less limiting than the hot zero power steamline break analysis. Therefore, the results of this case are not presented.

For all cases of excessive feedwater flow, continuous addition of cold feedwater is prevented by automatic closure of all feedwater control and isolation valves, closure of all feedwater bypass valves, a trip of the feedwater pumps, and a turbine trip on high-high steam generator water level. In addition, the feedwater pump discharge isolation valves automatically close upon receipt of the feedwater pump trip signal.

Following turbine trip, the reactor automatically trips, either directly due to the turbine trip or due to one of the reactor trip signals discussed in Section 2.8.5.2.1 (Loss of External Electrical Load and/or Turbine Trip). If the reactor was in automatic rod control, the control rods would be inserted at the maximum rate following the turbine trip, and the resulting transient would not be limiting in terms of peak RCS pressure.

The effects of the RTDP methodology, including rod control system response characteristics were incorporated into the analysis. Table 2.8.5.1.1.2.2-2 shows the time sequence of events for the multiple-loop hot full power feedwater malfunction transient. Figures 2.8.5.1.1.2.2-1 through 2.8.5.1.1.2.2-4 show transient responses for various system parameters during a feedwater system malfunction initiated from hot full power conditions with manual rod control.

For the excessive feedwater addition event, the results show that the DNBRs encountered are above the limit value; hence, no fuel damage is predicted.

The protection features presented in Section 2.8.5.1.1.2.2.2 provide mitigation of the feedwater system malfunction transient such that the above criteria are satisfied.

2.8.5.1.1.2.2.5 References

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

2. WCAP-14882-P-A (Proprietary), April 1999 and WCAP-15234-A (Nonproprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, Huegel, D. S., et al., May 1999.

3. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999.

2.8.5.1.1.2.3 Increase in Steam Flow

2.8.5.1.1.2.3.1 Introduction

An excessive load increase incident is defined as a rapid increase in steam flow that causes a mismatch between the reactor core power and the steam generator load demand. The reactor control system (RCS) is designed to accommodate a 10 percent step-load increase or a 5 percent per minute ramp-load increase in the range of 15 to 100 percent of full power. Any loading rate in excess of these values can cause a reactor trip actuated by the reactor protection system. If the load increase exceeds the capability of the reactor control system, the transient would be terminated in sufficient time to prevent the DNB design basis from being violated.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam bypass control system, or turbine speed control.

During power operation, steam dump to the condenser is controlled by comparing the RCS temperature to a reference temperature based on turbine power, where a high-temperature difference in conjunction with a loss-of-load or turbine trip indicates a need for steam dump. A single controller malfunction does not cause steam dump valves to open. Interlocks are provided to block the opening of the valves unless a large turbine load decrease or a reactor trip has occurred. In addition, the reference temperature and loss-of-load signals are developed by independent sensors.

Regardless of the rate of load increase, the reactor protection system trips the reactor in time to prevent the DNBR from going below the limit value. Increases in steam load to more than design flow are analyzed as the steam line rupture event in Section 2.8.5.1.2.2.1.2.

Protection against an excessive load increase accident, if necessary, is provided by the following reactor protection system signals:

- Overtemperature T (OTΔT)
- Overpower T (OPΔT)
- Power range high neutron flux

- Low-pressurizer pressure

2.8.5.1.1.2.3.2 Input Parameters, Assumptions, and Acceptance Criteria

The evaluation includes the following conservative assumptions:

- This accident is evaluated with the Revised Thermal Design Procedure (RTDP) (Reference 1). Initial reactor power, RCS pressure, and RCS temperature are assumed to be at their nominal values, consistent with steady-state full-power operation. Minimum measured flow (MMF) is assumed. Uncertainties in initial conditions are included in the DNBR limit as described in Reference 1. The initial conditions for the event are summarized in Table 2.8.5.0-1.
- The evaluation is performed for a step-load increase of 10 percent steam flow from 100 percent of core power.
- This event is evaluated for both automatic and manual rod control.
- The excessive load increase event is evaluated for both the minimum reactivity feedback and maximum reactivity feedback conditions.

Based on its frequency of occurrence, the excessive load increase accident is considered a Condition II event as defined by the ANS. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the RCS and MSS should be maintained below 110 percent of the design pressures.
- The peak linear heat generation rate (expressed in kW/ft) should not exceed a value that would cause fuel centerline melt.
- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

2.8.5.1.1.2.3.3 Description of Analyses and Evaluations

Given the non-limiting nature of this event with respect to the departure from nucleate boiling ratio (DNBR) safety analysis criterion, an explicit analysis was not performed as part of the SPU program. Instead, an evaluation of this event was performed. The evaluation model consists of the generation of statepoints based on generic conservative data. The statepoints are in the form of changes in temperature, pressure, power and flow that are applied to the plant's initial conditions. The changes in temperature, pressure, power and flow that are applied to generate the statepoints are based on analyses from numerous Westinghouse plants and represent the maximum deviation that results at any time during the transient. In addition to the generic deviation applied to the initial conditions, uncertainties are also applied in the conservative direction to generate the final statepoints. The statepoints are then compared to the core thermal limits to ensure that the DNBR limit is not violated. A total of three cases were included in the evaluation. These are:

- Reactor in manual rod control with minimum moderator reactivity feedback
- Reactor in manual rod control with maximum moderator reactivity feedback
- Reactor in automatic rod control (both minimum/maximum moderator reactivity feedback)

The automatic rod withdrawal feature is being eliminated at MPS3 as part of the SPU program. However, the case for the reactor in automatic rod control was still evaluated since the combination of automatic rod insertion and withdrawal is more limiting than automatic rod insertion only for this event.

The method of analysis discussion presented below corresponds to the analysis previously performed for this event and is provided for historical purposes.

Historically, four cases were analyzed, and presented in the FSAR, to demonstrate the plant behavior following a 10 percent step-load increase from 100 percent load. These cases are as follows:

- Reactor in manual rod control with minimum moderator reactivity feedback
- Reactor in manual rod control with maximum moderator reactivity feedback
- Reactor in automatic rod control with minimum moderator reactivity feedback
- Reactor in automatic rod control with maximum moderator reactivity feedback

For the minimum-moderator feedback cases, the core has the least-negative moderator temperature coefficient of reactivity and therefore, the least-inherent transient response capability. For the maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its most-negative value. This results in the largest amount of reactivity feedback due to changes in coolant temperature. Normal reactor control systems and engineered safety systems are not required to function.

A 10 percent step increase in steam demand was assumed. No credit was taken for the operation of the pressurizer heaters. The cases that assumed automatic rod control were analyzed to ensure that the worst case was presented. The automatic function was not required. The reactor protection system was assumed to be operable; however, reactor trip was not encountered for the cases analyzed. No single active failure in any system or component required for mitigation would adversely affect the consequences of this accident.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the excessive load increase analysis. As stated in Section 2.8.5.1.1.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.1.1.2.3.4 Results

The evaluation performed for the SPU confirmed that for an excessive load increase, the minimum DNBR during the transient does not go below the safety analysis limit value and the peak linear heat generation does not exceed the limit value, thus demonstrating that the applicable acceptance criteria for critical heat flux and fuel centerline melt are met. Following the initial load increase, the plant reaches a stabilized condition. With respect to peak pressure, the excessive load increase accident is bounded by the loss-of-electrical-load/turbine-trip analysis. The loss-of-electrical-load/turbine-trip analysis is described in Section 2.8.5.2.1.

In addition, no adverse conditions are generated as a result of this event that would lead to a more serious plant condition without other faults occurring independently. All applicable acceptance criteria are therefore met.

The protection features presented in Section 2.8.5.1.1.2.3.1 provide mitigation for the excessive load increase incident such that the above criteria are satisfied.

2.8.5.1.1.2.3.5 References

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

2.8.5.1.1.2.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve

The inadvertent opening of a steam generator relief or safety valve event is more commonly referred to as a credible steamline break. It is always bounded by the analysis of the large steamline break (referred to as the hypothetical steamline break) presented in the FSAR Section 15.1.5. The hypothetical steamline break is a Condition IV event that is analyzed to Condition II acceptance criteria. The credible steamline break is a Condition II event. Since the more severe Condition IV event is shown to meet the more restrictive Condition II acceptance criteria, it can be concluded that the credible steamline break event also meets the Condition II acceptance criteria. As such, no explicit analysis of the credible steamline break has been performed. The analysis documented in Section 2.8.5.1.2.2.1 (and FSAR, Section 15.1.5) demonstrates that all applicable acceptance criteria are met for the hypothetical steam line break and, subsequently, all acceptance criteria are met for the credible steamline break.

2.8.5.1.1.3 Conclusion

DNC has reviewed the analyses of the excess heat removal events described above and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -10, -15, -20, and -26 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the events stated.

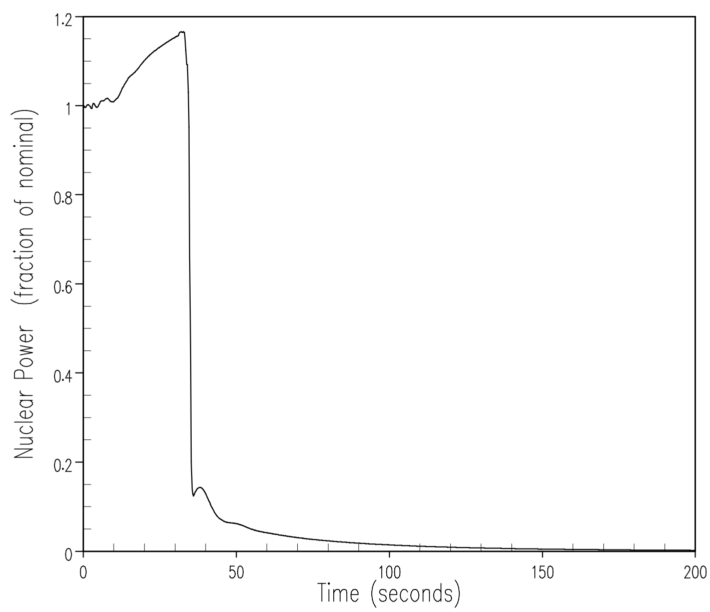
Table 2.8.5.1.1.2.2-1
Cases Considered Using RETRAN

Case	Power Level	Failure	Affected Loop(s)	Rod Control
1	HFP	MFCV	Loop 1	Auto
2	HFP	MFCV	Loop 1	Manual
3	HFP	MFCV	All	Auto
4	HFP	MFCV	All	Manual
5	HZP	MFCV	Loop 1	Manual
6	HZP	MFCV	All	Manual

Table 2.8.5.1.1.2.2-2
Time Sequence of Events – Excessive Heat Removal Due to Feedwater System Malfunctions

Event	Time (seconds)
All MFCVs Fail Full Open	0.01
High-high SG water level setpoint reached (100% NRS)	28.0
Turbine Trip initiated	30.4
Reactor Trip on Turbine Trip – rod motion initiated	32.4
Minimum DNBR (1.88) reached	32.5
Feedwater isolation initiated	34.9

Figure 2.8.5.1.1.2.2-1
Multiple-Loop MFCV Malfunction at Full-Power
Nuclear Power and Core Heat Flux vs. Time



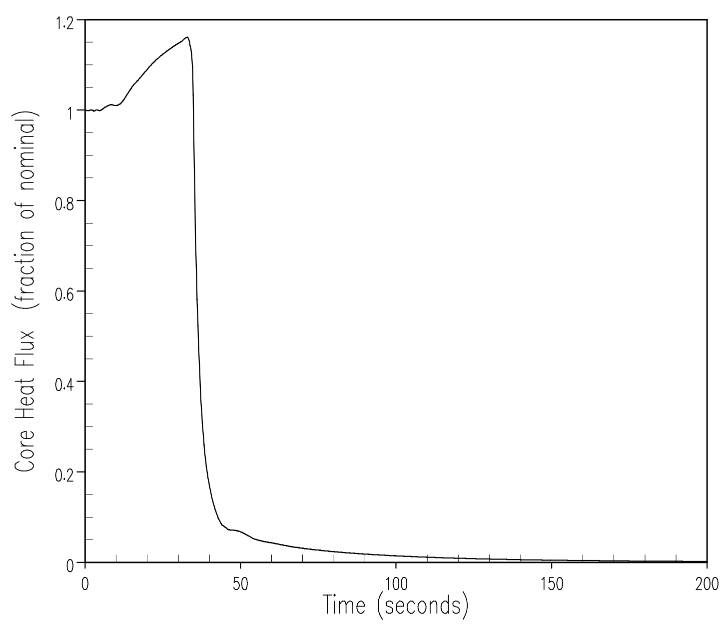
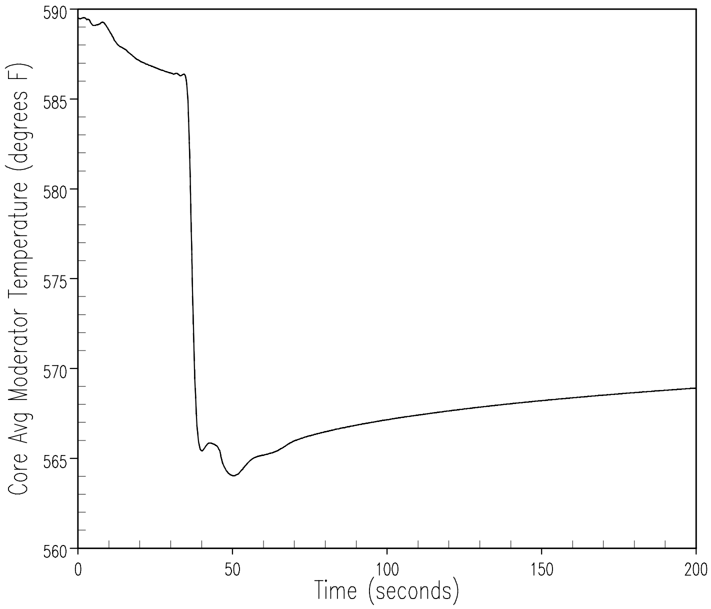


Figure 2.8.5.1.1.2.2-2
Multiple-Loop MFCV Malfunction at Full-Power
Core Average Temperature and Pressurizer Pressure vs. Time



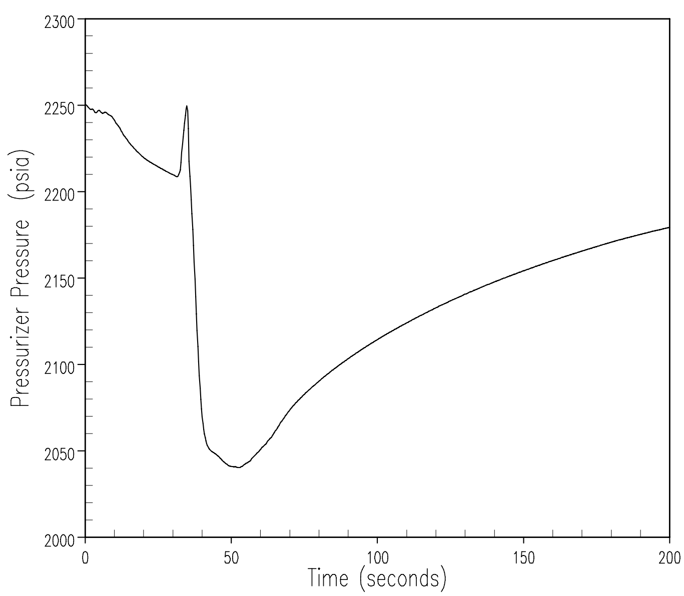


Figure 2.8.5.1.1.2.2-3
Multiple-Loop MFCV Malfunction at Full-Power
DNBR vs. Time

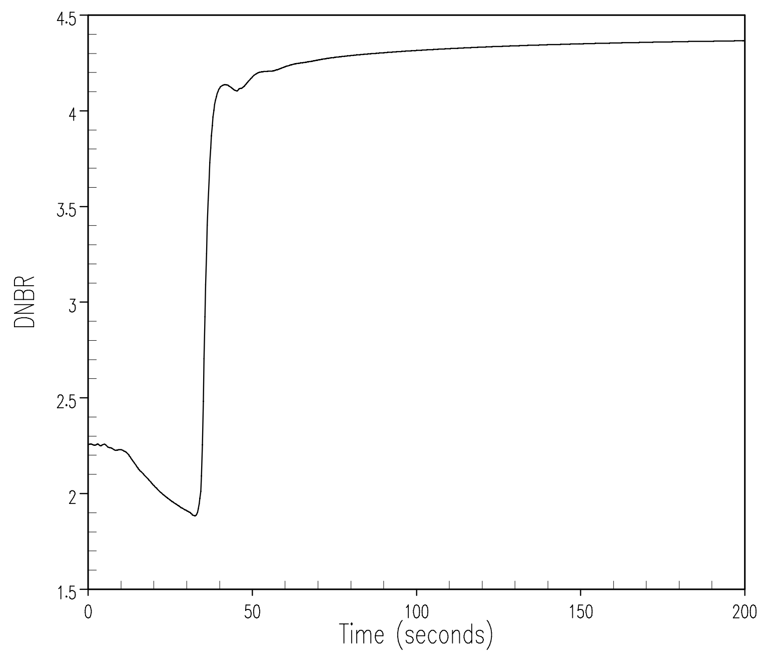
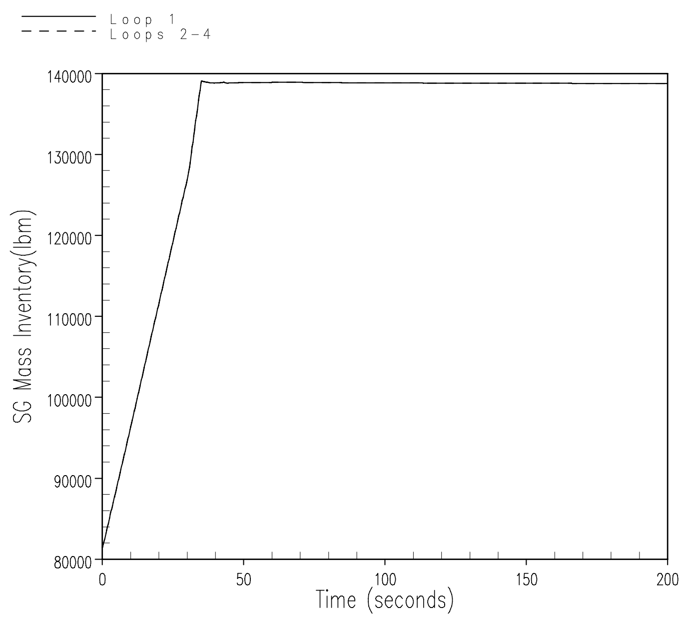
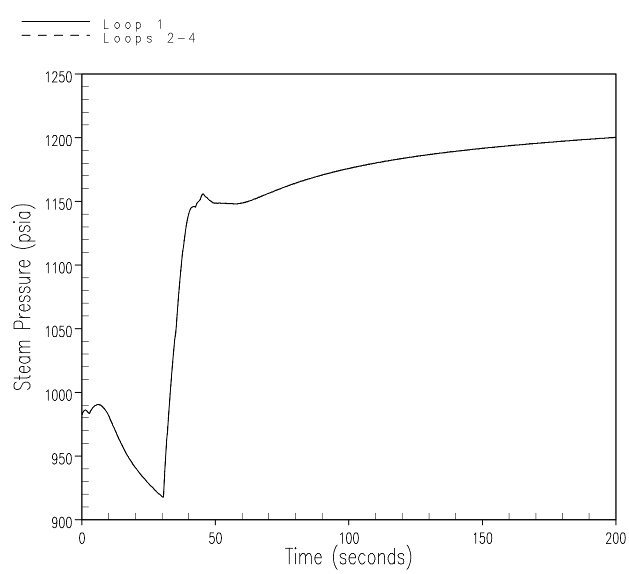


Figure 2.8.5.1.1.2.2-4
Multiple-Loop MFCV Malfunction at Full-Power
Steam Generator Mass and Pressure vs. Time





2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment

2.8.5.1.2.1 Regulatory Evaluation

The steam release resulting from a rupture of a main steam pipe will result in an increase in steam flow, a reduction of coolant temperature and pressure, and an increase in core reactivity. The core reactivity increase may cause a power level increase and a decrease in shutdown margin. Reactor protection and safety systems are actuated to mitigate the transient.

The DNC review covered:

- The postulated initial core and reactor conditions
- The methods of thermal and hydraulic analyses
- The sequence of events
- The assumed responses of the reactor coolant and auxiliary systems
- The functional and operational characteristics of the RPS
- Operator actions
- Core power excursion due to power demand caused by excessive steam flow
- Variables influencing neutronics
- The results of the transient analyses

The acceptance criteria are based on:

- GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained
- GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core
- GDC-31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specific conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized
- GDC-35, insofar as it requires that the RCS and associated auxiliaries be designed to provide abundant emergency core cooling.

Specific review criteria are contained in the SRP Section 15.1.5, and other guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 15.1.5, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2. As stated in FSAR Section 15.0.1, steam system piping failures, which also lead to an increase in heat removal from the RCS, may be either ANS Condition III (small breaks) or Condition IV (Large breaks) events.

Specifically, the adequacy of MPS3’s design relative to:

- GDC-27, Combined Reactivity Control System Capability, is described in FSAR Section 3.1.2.27.

  The facility is provided with means of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. FSAR Chapters 4 and 9 discuss these means in detail. Combined use of the rod cluster control system and the chemical shim control system permits the necessary shutdown margin to be maintained during long term xenon decay and plant cooldown. The single highest worth rod cluster is assumed to be stuck full-out upon trip for this determination. FSAR Section 15.1.5 provides a description and analysis of steam system piping failures.

- GDC-28, Reactivity Limits, is described in FSAR Section 3.1.2.28.

  The maximum reactivity worth of control rods and the maximum rates of reactivity insertion employing control rods are limited to values that prevent rupture of the RCS boundary or disruptions of the core or vessel internals to a degree that could impair the effectiveness of emergency core cooling. This design basis is further described in FSAR Section 4.3.1.

  Assurance of core cooling capability following Condition IV accidents, such as rod ejections, steam line break, etc., is given by keeping the reactor coolant pressure boundary stresses within faulted condition limits as specified by applicable ASME Codes. Structural deformations are checked also and limited to values that do not jeopardize the operation of necessary safety features.

- GDC-31, Fracture Prevention of Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.31.

  Close control is maintained over material selection and fabrication for the RCS to assure that the boundary behaves in a non-brittle manner. The RCS materials exposed to the coolant are corrosion resistant stainless steel or Inconel. The NIL ductility reference temperature of the RV structural steel is established by Charpy V-notch and drop weight tests, in accordance with 10 CFR 50, Appendix G.

  Allowable pressure-temperature relationships for plant heatup and cooldown rates are calculated using methods derived from the ASME Code, Section III, Appendix G, Protection Against Non-Ductile Failure. This approach specifies that allowed stress intensity factors for all vessel operating conditions may not exceed the referenced stress intensity factor (KIR) for the metal temperature at any time. Operating specifications include conservative margins for predicted changes in the material reference temperature due to irradiation.

- GDC-35, Emergency Core Cooling, is described in FSAR Section 3.1.2.35.

  An ECCS is provided to cope with any LOCA in the plant design basis. Abundant cooling water is available in an emergency to transfer heat from the core at a rate that clad metal-water reaction is limited to less than one per cent. Adequate design provisions are made to assure performance of the required safety functions even with a single failure. The ECCS is described in more detail in FSAR Section 6.3.

FSAR Table 15.1-2 lists the equipment required in the recovery from a high-energy line rupture. Not all equipment is required for any one particular break, since the requirements vary depending upon postulated break locations and details of balance of plant design and pipe rupture criteria as discussed elsewhere in this application. Design criteria and methods of protection of safety related equipment form the dynamic effects of postulated piping ruptures are provided in FSAR Section 3.6.

FSAR Table 15.1-3 contains assumptions used in the MSLB analysis. As stated in FSAR Section 15.1.5.2, the LOFTRAN Code (WCAP-7907-P-A) has been used to determine the core heat flux and RCS temperature and pressure resulting from the cooldown following the steam line break. THINC has been used to determine if DNB occurs for the core conditions computed in WCAP-7907-P-A.

FSAR Section 15.1.5.3 concludes that no DNB occurs for any steam pipe rupture assuming the most reactive RCCA stuck in its fully withdrawn position.

NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of license renewal.

2.8.5.1.2.2 Technical Evaluation

2.8.5.1.2.2.1 Steam System Piping Failure at Hot Zero Power

2.8.5.1.2.2.1.1 Introduction

The steam release arising from a major rupture of a main steam pipe results in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The increased energy removal from the RCS causes a reduction of reactor coolant temperature and pressure. In the presence of a negative moderator temperature coefficient (MTC), the cooldown results in a positive reactivity insertion and subsequent reduction in core shutdown margin. If the most-reactive rod cluster control assembly (RCCA) is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core becomes critical and returns to power. A return to power following a steam pipe rupture is a concern primarily because of the high-power peaking factors that would exist assuming the most-reactive RCCA is stuck in its fully withdrawn position.

The major rupture of a main steam pipe is the most-limiting cooldown transient. It is analyzed at HZP conditions with no decay heat (decay heat would retard the cooldown, thus reducing the return to power). A detailed discussion of this transient with the most limiting break size (a double-ended rupture) is presented below.

The primary design features which provide protection for steam pipe ruptures are:

- Actuation of the SI system from any of the following:
  - Two-out-of-four pressurizer low-pressure signals.
  - Two-out-of-three low-pressure signals in any steam line.
  - Two-out-of-three high-containment pressure signals.
- Reactor trip can be actuated from overpower neutron flux, overpower delta T (OPΔT), low pressurizer pressure or upon actuation of the SI system.
- Redundant isolation of the main feedwater lines to prevent sustained high-feedwater flow that would cause additional cooldown. In addition to the normal control action which closes the main feedwater control valves, an SI signal rapidly closes all feedwater control valves and backup feedwater isolation valves, and trips the main feedwater pumps. A trip of the main feedwater pumps results in automatic closure of the respective pump discharge isolation valve.
- Trip of the fast-acting main steamline isolation valves (MSIVs), on the following:
  - High-high containment pressure.
  - Safety injection system actuation derived from two-out-of-three low steam line pressure signals in any loop
  - High negative steam pressure rate indication from two-out-of-three signals in any loop (below permissive P-11)

For any break (in any location), no more than one steam generator would experience an uncontrolled blowdown even if one of the MSIVs fails to close. For breaks downstream of the MSIVs, closure of all MSIVs completely terminates the blowdown of all steam generators. The MSIVs are signal-actuated valves that close to prevent flow in the normal (forward) flow direction. The valves on all steam lines are closed to isolate the steam generators. Thus, even with the worst possible break location (i.e., upstream of an MSIV), only one steam generator can blow down, minimizing the potential steam release and resultant RCS cooldown. The remaining steam generators would still be available for dissipation of decay heat after the initial transient is over.

Following blowdown of the faulted steam generator, the unit can be brought to a stabilized hot-standby condition through control of the auxiliary feedwater (AFW) flow and SI flow as described by plant operating procedures. The operating procedures call for operator action to limit RCS pressure and pressurizer level by terminating SI flow and to control steam generator level and RCS coolant temperature using the auxiliary feedwater system (AFWS).

2.8.5.1.2.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The following summarizes the major input parameters and/or assumptions used in the main steam line rupture event:

- HZP conditions were modeled with four loops in service with and without offsite power available.
- For MPS3, a 1.388 ft^2 break was analyzed for the Model F steam generators, since they are designed with a flow restrictor built into the steam exit nozzle. The assumed steam generator tube plugging level was 0 percent.
- All control rods were inserted except the most reactive RCCA, which was assumed to be stuck out of the core.
- The shutdown margin was 1.30 percent k/k.
- The safety injection system and the accumulators are conservatively assumed to contain no boron.
- Only the two-out-of-four pressurizer low-pressure signal is credited for safety injection actuation.
- The initial steam generator water level (and associated mass) is assumed to be at the nominal level for HZP.
- The initial conditions for the event are as summarized in Table 2.8.5.0-1.

A major break in a steam system pipe is classified as an ANS Condition IV event. Minor secondary system pipe breaks are classified as ANS Condition III events. All of these events were analyzed to meet Condition II criteria.

Primary and secondary pressure limits are not challenged because primary and secondary pressures decrease from their initial values during the transient. The only criterion that has the potential to be challenged during this event is that concerning the critical heat flux not being exceeded. The analysis demonstrates that this criterion is met by showing that the minimum DNBR does not go below the limit value at any time during the transient.

2.8.5.1.2.2.1.3 Description of Analyses and Evaluations

A detailed analysis using the RETRAN (Reference 1) computer code was performed in order to determine the plant transient conditions following a main steam line break. The code models the core neutron kinetics, RCS, pressurizer, steam generators, SI system and the AFWS; and computes pertinent variables, including the core heat flux, RCS temperature, and pressure. A conservative selection of those conditions was then used to develop core models which provide input to the detailed thermal and hydraulic digital computer code, VIPRE (Reference 2), to determine if the DNB design basis is met.

These computer codes are different than those used for the current licensing basis analysis where the LOFTRAN (WCAP-7907-P-A) and THINC codes are used. RETRAN and VIPRE have been approved by the NRC for the analysis of steam system piping failures (References 1 and

2). Section 2.8.5.0 of this report contains a discussion of the applicability of these computer codes and compliance with the SER limitations for these codes for Millstone 3.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the steam system piping failure analysis. As stated in Section 2.8.5.1.2.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.1.2.2.1.4 Results

For MPS3, the most limiting main steamline rupture at HZP case is the case in which offsite power is assumed to be available. The calculated sequence of events for this case is shown in Table 2.8.5.1.2.2.1-1. The case with offsite power available is more limiting than the case without offsite power due to the continued forced cooling when offsite power is available. This results in a lower coolant temperature and greater reactivity feedback due to the large assumed end-of-life density coefficient.

Figures 2.8.5.1.2.2.1-1 through 2.8.5.1.2.2.1-6 show the transient results for the most limiting case for MPS3. These figures show transient results following a main steamline rupture (complete severance of a pipe) at initial no-load conditions with offsite power available. Since offsite power is assumed available, there is full reactor coolant flow. Figure 2.8.5.1.2.2.1-7 presents the safety injection flow modeled for this transient as a function of pressure.

Should the core be critical at or near zero power when the rupture occurs, the initiation of SI via a low-steam line pressure signal trips the reactor. Steam release from more than one steam generator is prevented by automatic trip of the fast acting isolation valves in the steam lines by high-containment pressure or by low steam line pressure signals.

As shown in Figure 2.8.5.1.2.2.1-4 the core attains criticality with the RCCAs inserted (i.e., with the plant shutdown assuming one stuck RCCA) before steam generator dry-out occurs and subsequently turns the transient around.

The results of the major rupture of a main steam pipe event indicate that the DNB design basis is met. The DNBR calculation was performed using the W-3 DNB correlation. The calculated minimum DNBR is 1.77 compared to a limit of 1.45. Primary and secondary pressure limits are not challenged because primary and secondary pressures decrease from their initial values during the transient. Therefore, this event does not adversely affect the core or the RCS, and all applicable acceptance criteria are met.

2.8.5.1.2.2.1.5 References

1. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Nonproprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, Huegel, D. S., et al., April and May 1999, respectively.

2. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X., et al., October 1999.

2.8.5.1.2.2.2 Steam System Piping Failure at Full-Power

2.8.5.1.2.2.2.1 Introduction

This section describes the analysis of a steam system piping failure occurring from at-power initial conditions to demonstrate that core protection is maintained prior to and immediately following reactor trip.

2.8.5.1.2.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Limiting transient condition statepoints were generated using the Revised Thermal Design Procedure (RTDP) (Reference 1). For RTDP applications, uncertainties on RCS initial conditions (temperature, pressure, and power) are included in the development of the DNBR limit value. When RTDP is not applicable, uncertainties are included in the initial conditions or are conservatively applied to the limiting transient condition in the calculation of the minimum DNBR. When statepoints are generated for use in both an RTDP application (i.e., DNBR) and a non-RTDP application (i.e., peak kW/ft calculation), the uncertainties are not included in the analysis that generates the statepoints. The uncertainties are included in the DNBR limit for the DNBR calculation and are conservatively added to the statepoint for the peak kW/ft calculation.

- Initial conditions – The initial core power, RCS temperature, and RCS pressure are assumed to be at their nominal steady-state, full-power values when generating the transient statepoints. Uncertainties are explicitly included in the DNBR calculations.
- RCS flow – Minimum measured RCS flow is assumed when generating the transient statepoints. The thermal design flow (TDF) is assumed in the DNBR calculations. The initial loop flows are assumed to be symmetric.
- RCS average temperature – The full-power RCS T_{avg} range is from 571.5°F to 589.5°F. Since the full-power steamline-rupture-core-response event is a DNB event, assuming a maximum RCS average temperature of 589.5°F is limiting.
- Feedwater temperature – The main feedwater analytical temperature range is from 390° to 445.3°F. A nominal feedwater temperature of 445.3°F is more limiting with respect to DNB for this event. Thus, a feedwater temperature of 445.3°F is assumed.
- The initial conditions for the event are summarized in Table 2.8.5.0-1.

- Break size – The event is analyzed over a spectrum of break sizes in order to identify the most limiting overpower condition, which is typically identified by the largest break to produce a reactor trip on overpower delta T (OPΔT). The steam generators in MPS3 have a steam exit nozzle flow restrictor that limits the flow area to 1.388 ft^2. Therefore the analysis modeled break sizes up to 1.4 ft^2. In addition, the largest break size for which there is no reactor trip is examined to determine if it is more limiting with respect to peak power level.
- Reactivity coefficients – The analysis assumed maximum moderator reactivity feedback and minimum Doppler power feedback to maximize the power increase following the break.
- Protection system – The protection system features that mitigate the effects of a steamline break are described in Section 2.8.5.1.2.2.1. This analysis only considers the initial phase of the transient from at-power conditions. Protection in this phase of the transient is provided by reactor trip, if necessary. Section 2.8.5.1.2.2.1 presents the analysis of the bounding transient following reactor trip, where other protection system features are actuated to mitigate the effects of the steamline break. The individual components of the instrumentation delays and lag times (such as the RTDs, the filters and the delay from reaching the trip setpoint until the rods begin to fall into the core) are explicitly modeled. The effects of excore temperature shadowing do not need to be addressed because the high neutron flux reactor trip is not credited in this event.
- Control systems – The only control system that is assumed to function during a full-power-steamline-rupture-core-response event is the main feedwater system. For this event, the feedwater flow is set to match the steam flow.
- Single Failure – The worst single failure is the failure of one protection train, as other failures (such as a failure in the engineered safety features, a failure of a main steam isolation or feedwater line isolation valve, etc.) would occur beyond the time of reactor trip and are not relevant to the event as analyzed. These types of failures, including the loss of offsite power, are considered in the analysis of the HZP MSLB event, which examines post-reactor trip.

Depending on the size of the break, this event is classified as either a Condition III (infrequent fault) or Condition IV (limiting fault) event. However, the analysis results are compared to the more conservative Condition II acceptance criteria. The acceptance criteria for this event are consistent with those stated in Section 2.8.5.1.2.2.1.2.

2.8.5.1.2.2.2.3 Description of Analysis and Evaluations

The analysis of the steamline break at-power for the SPU was performed as follows:

- The RETRAN code (Reference 2) was used to calculate the nuclear power, core heat flux, and RCS temperature and pressure transients resulting from the cooldown following the steamline break.
- The core radial and axial peaking factors were determined using the thermal-hydraulic conditions from RETRAN as input to the nuclear core models. A detailed thermal-hydraulic code, VIPRE (Reference 3), was used to calculate the DNBR for the limiting time during the transient. The DNBR calculations were performed using the WRB-2M DNB correlation and RTDP.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the steam system piping analysis. As stated in Section 2.8.5.1.2.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.1.2.2.2.4 Results

The limiting break size from the spectrum of break sizes analyzed is 0.86 ft^2, with a minimum DNBR of 2.068/2.099 (thimble/no insert), and a peak fuel rod power of 21.0 kW/ft. The sequence of events for the limiting case with a 0.86 ft^2 break is shown in Table 2.8.5.1.2.2.2-1. Table 2.8.5.1.2.2.2-2 presents the results of break spectrum analyzed for the MPS3 HFP SLB event, including the large breaks that trip on the low steamline pressure safety injection signal reactor trip, the intermediate break sizes that trip on the Overpower ΔT reactor trip, and the small break sizes that do not induce a reactor trip. Plots for the limiting case are provided in Figures 2.8.5.1.2.2.2-1 through 2.8.5.1.2.2.2-4.

The 0.86 ft^2 break size is the most limiting break size with respect to peak heat flux and minimum DNBR for the full-power-steamline-rupture-core-response event.

The DNB design basis is met. The peak linear heat generation rate (expressed in kW/ft) did not exceed a value that would cause fuel centerline melting, and the clad stress/strain criteria have been shown to be met. Therefore, this event does not adversely affect the core or RCS, and all applicable criteria are met.

The results and conclusions of the analysis performed for the steam system piping failure at full-power for the NSSS power of 3666 MWt bound and support the implementation of the SPU. Furthermore, the results and conclusions of this analysis are confirmed on a cycle specific basis as part of the normal reload process.

2.8.5.1.2.2.2.5 References

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

2. WCAP-14882-P-A (Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, Huegel, D.S., et al., April 1999.

3. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999.

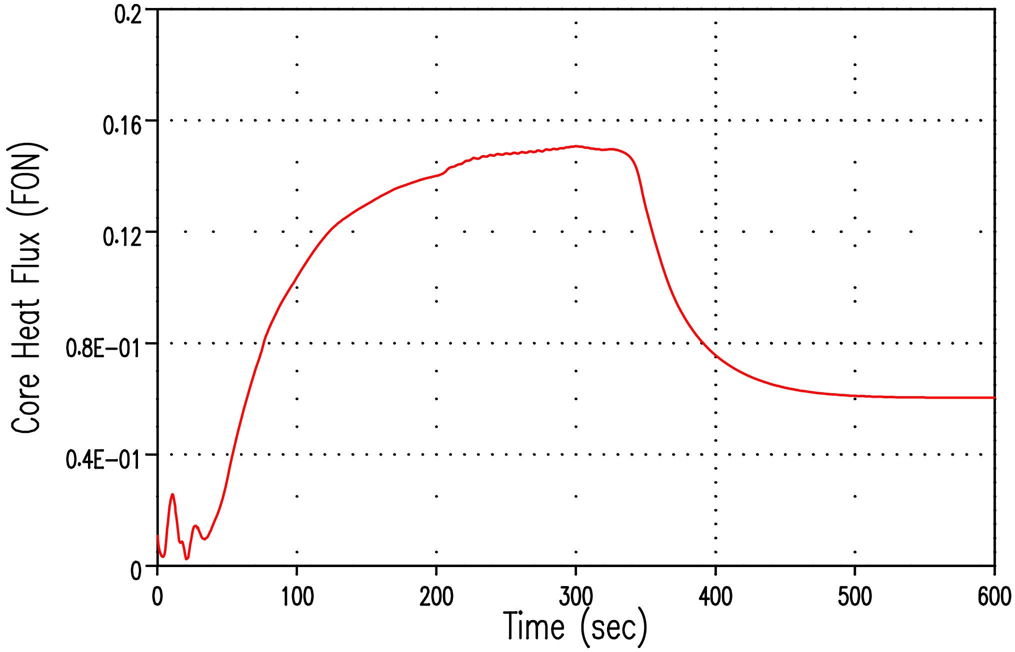
2.8.5.1.2.3 Conclusion

DNC has reviewed the analyses of steam system piping failure events and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of a propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -27, -28, 31, and -35 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to steam system piping failures.

Table 2.8.5.1.2.2.1-1
MPS3 Time Sequence of Events – Steam System Piping Failure

Case	Event	Time (sec)
Reactor at HZP with Offsite Power Available	Double-Ended Guillotine Break Occurs	0.0
	Low Steam Pressure Setpoint Reached in Faulted Loop	0.5
	Low Steam Pressure Setpoint Reached in Intact Loops	1.4
	Feedwater Isolation (on SI signal on low steam pressure) Complete	7.5
	Steamline Isolation (on low steam pressure) Complete	12.5
	Pressurizer Empties	20.5
	Low Pressurizer Pressure Setpoint Reached	23.8
	Safety Injection Signal (on low pressurizer pressure) Generated	25.8
	Re-criticality Occurs	28.0
	SI Flow Initiated	72.8
	Peak Nuclear Power Reached	300.0
	Peak Heat Flux Reached	300.0
	Minimum DNBR Reached	300.5

Figure 2.8.5.1.2.2.1-1
MPS3 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break
(with Offsite Power Available)
Nuclear Power, and Core Heat Flux vs. Time



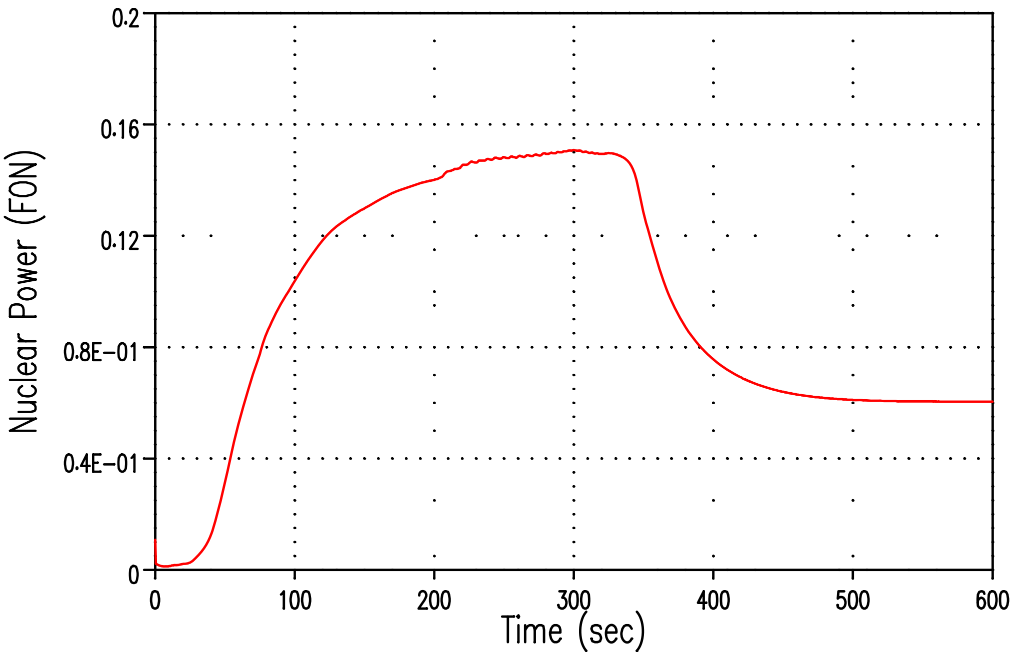


Figure 2.8.5.1.2.2.1-2
MPS3 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break
(with Offsite Power Available)
Core Average Temperature, and Core Boron Concentration vs. Time

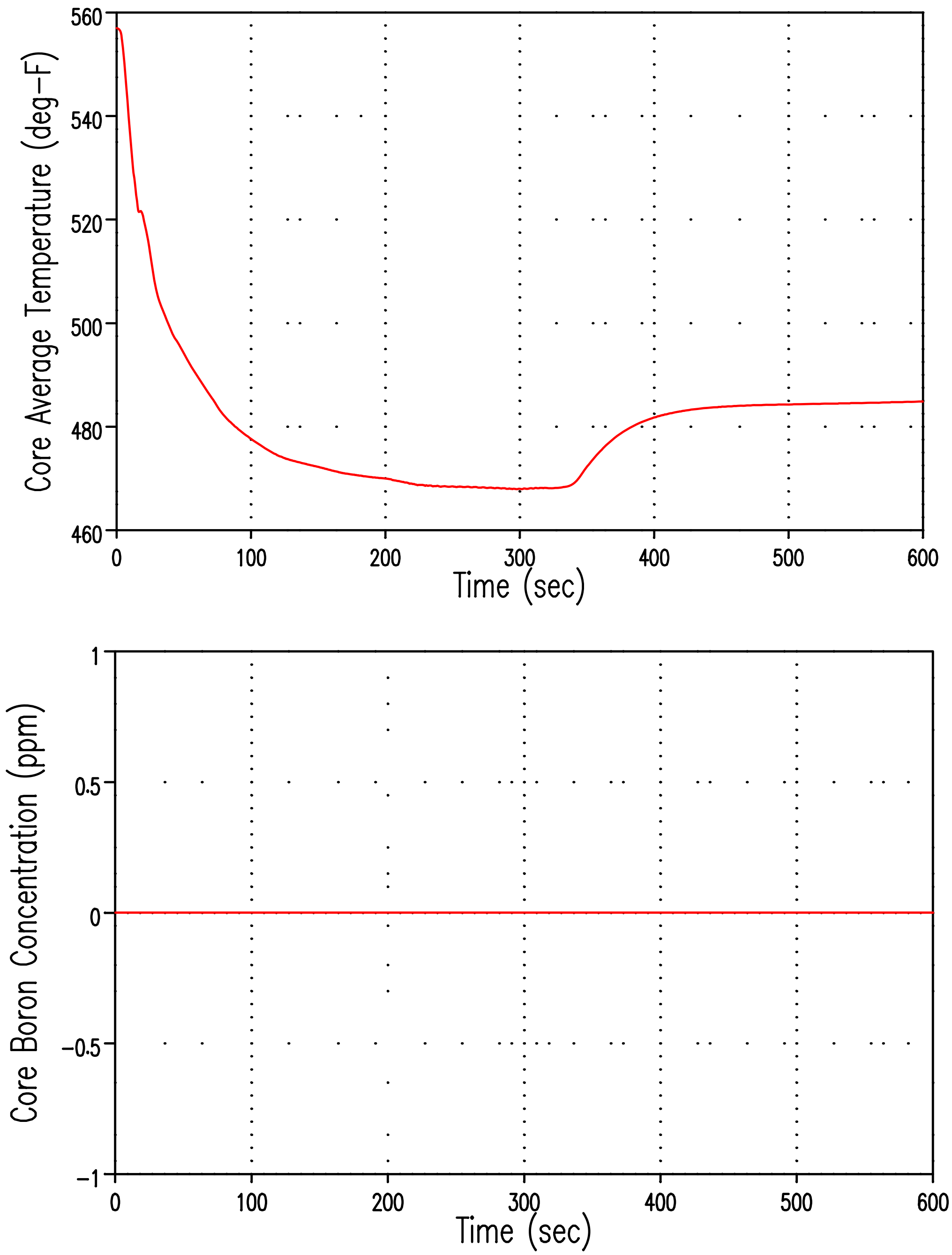
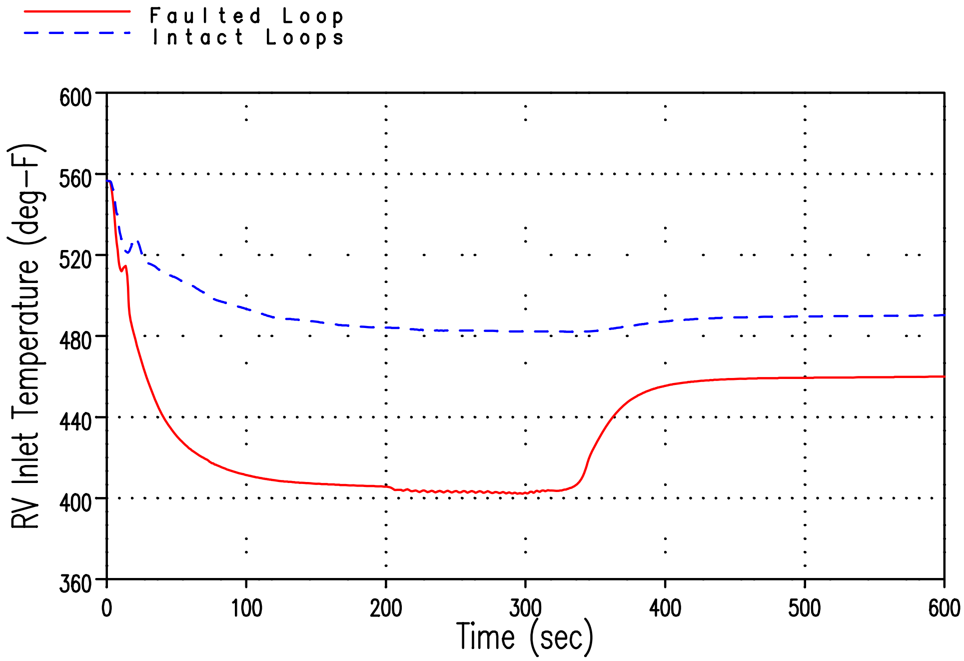


Figure 2.8.5.1.2.2.1-3
MPS3 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break
(with Offsite Power Available)
Reactor Vessel Inlet Temperature, and Pressurizer Pressure vs. Time



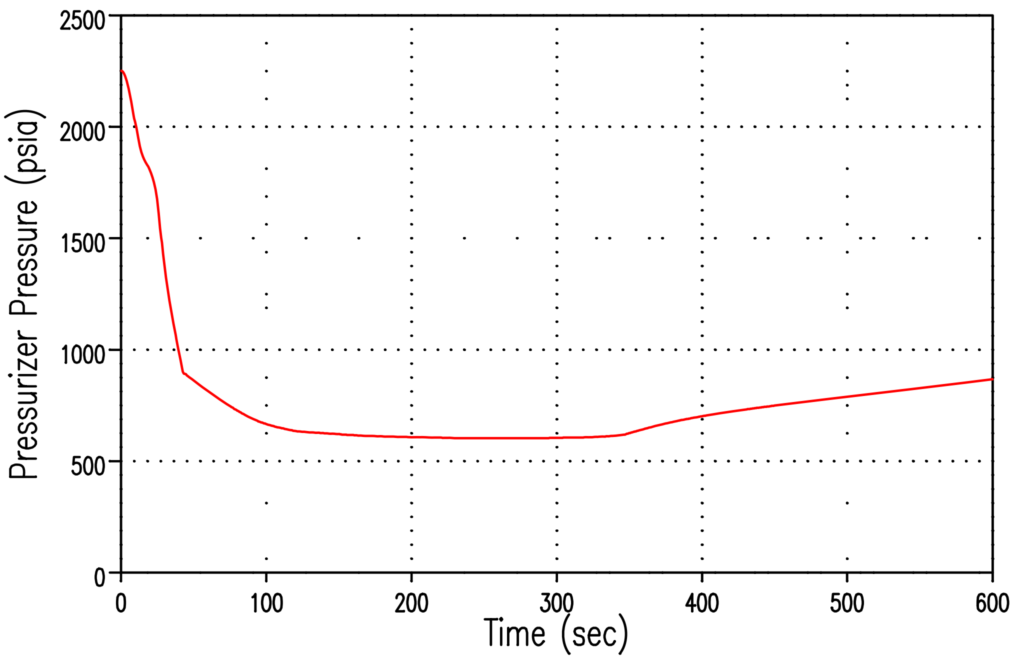
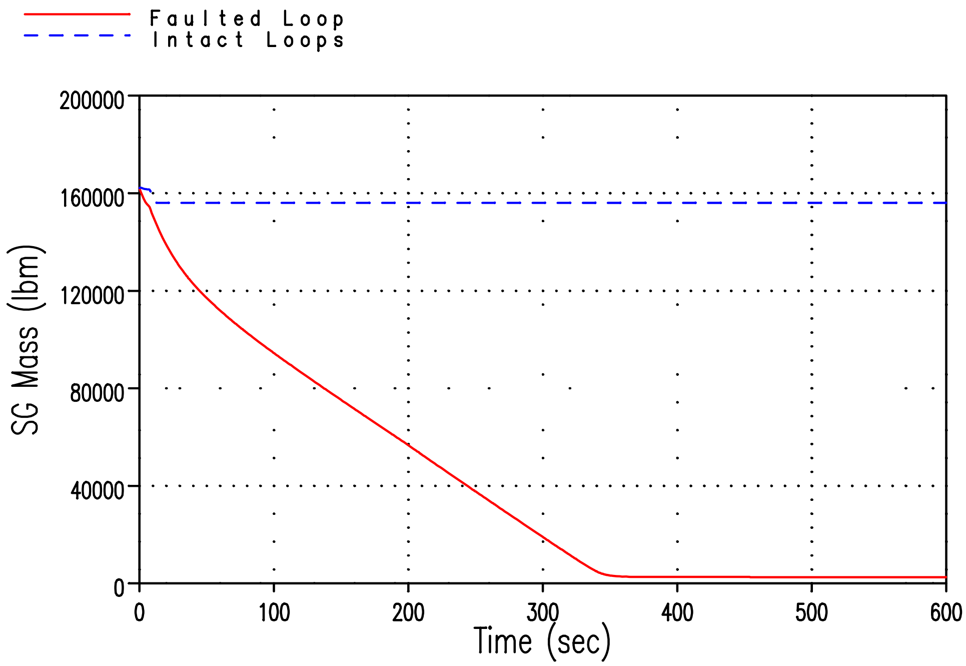


Figure 2.8.5.1.2.2.1-4
MPS3 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break
(with Offsite Power Available)
Reactivity, and Steam Generator Mass vs. Time



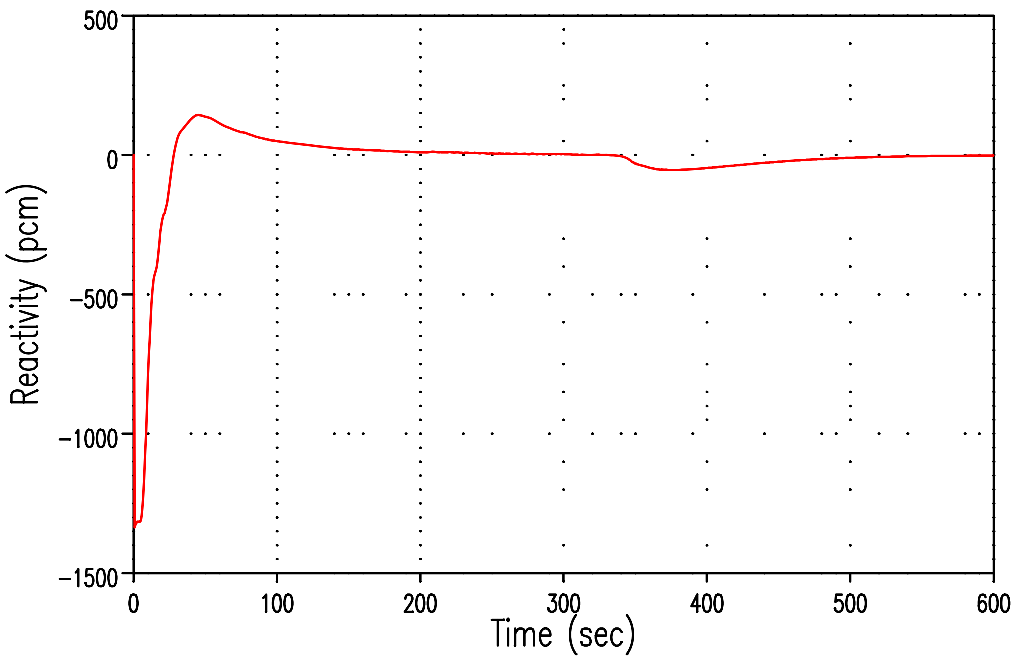
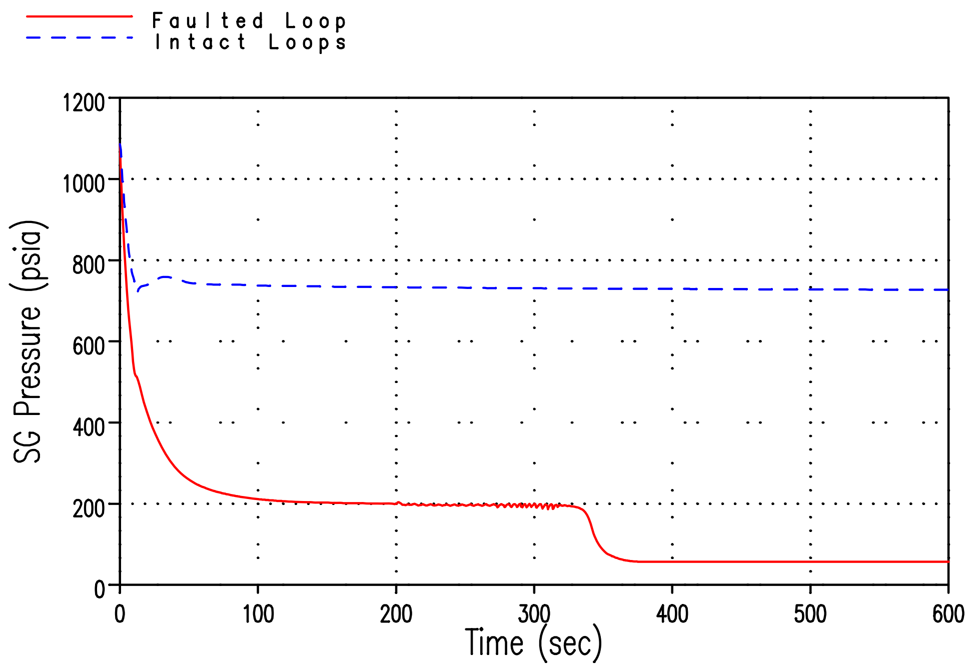


Figure 2.8.5.1.2.2.1-5
MPS3 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break
(with Offsite Power Available)
Steam Flow, and Steam Generator Pressure vs. Time



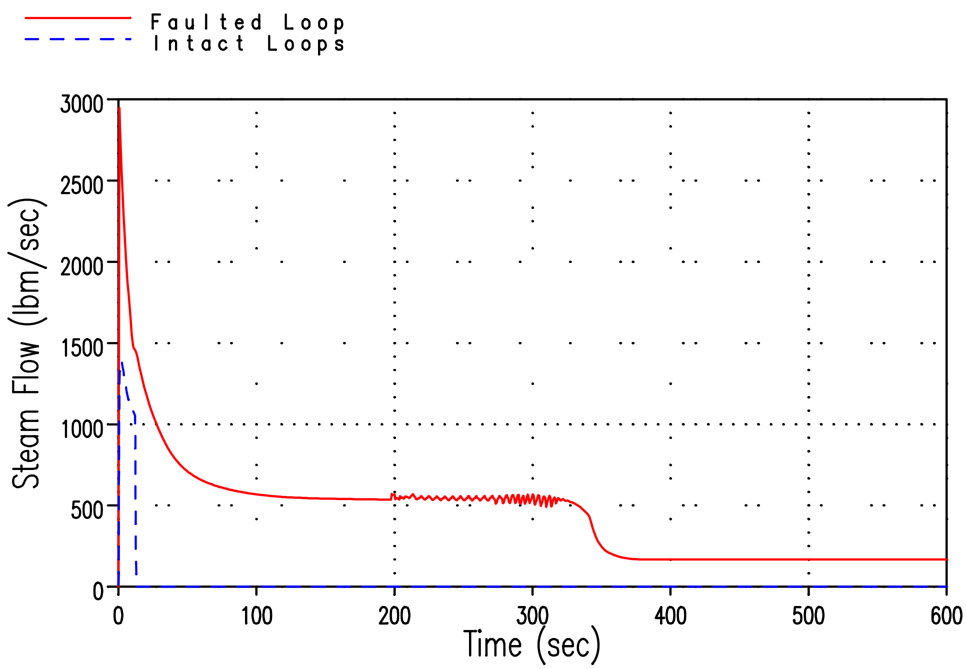


Figure 2.8.5.1.2.2.1-6
MPS3 Steam System Piping Failure at Hot Zero Power – 1.388 ft^2 Break
(with Offsite Power Available)
Pressurizer Water Volume, and Feedwater Flow (Main and Auxiliary) vs. Time

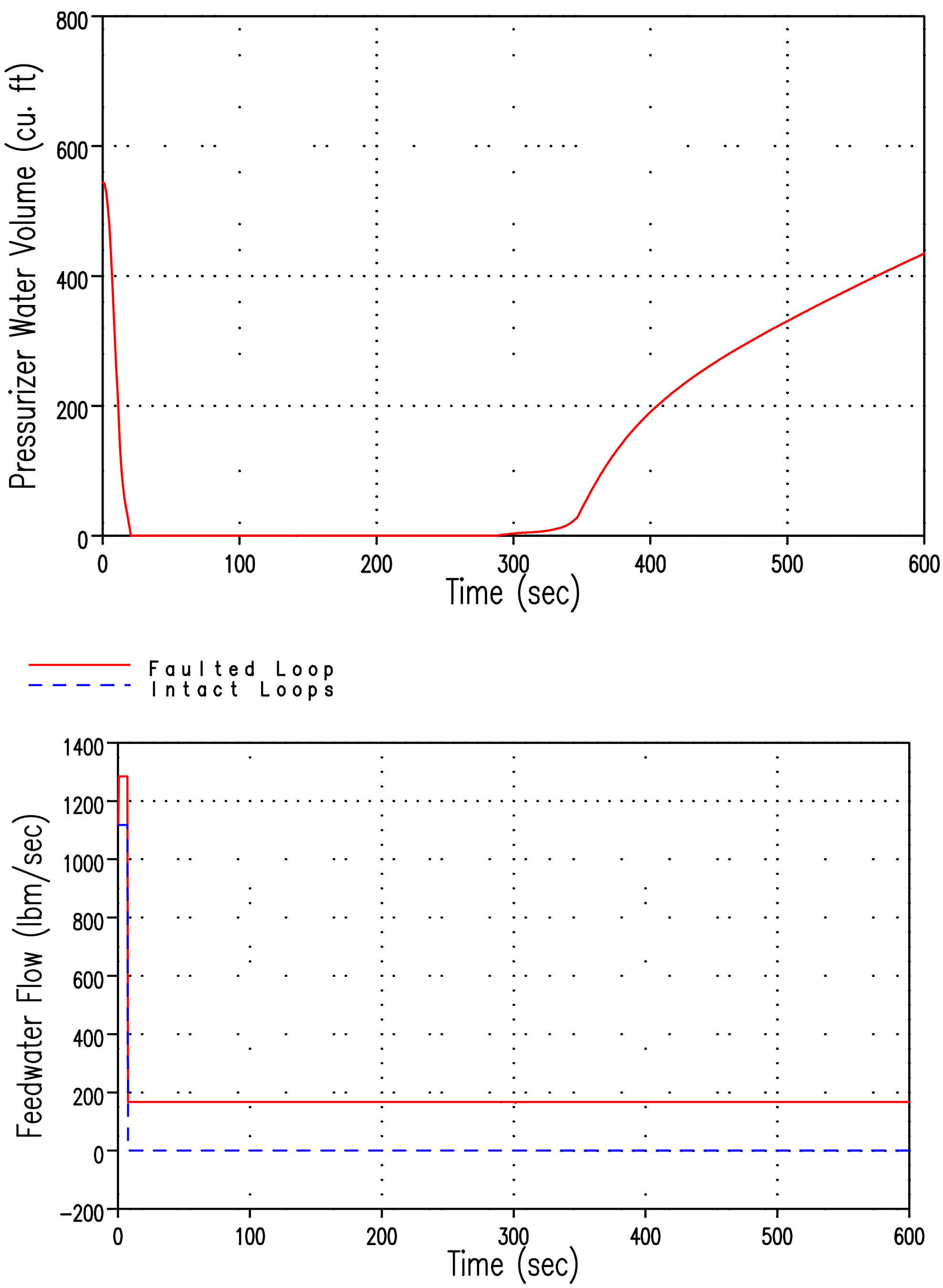


Figure 2.8.5.1.2.2.1-7
MPS3 Steam System Piping Failure at Hot Zero Power
Safety Injection Flow vs. Pressure

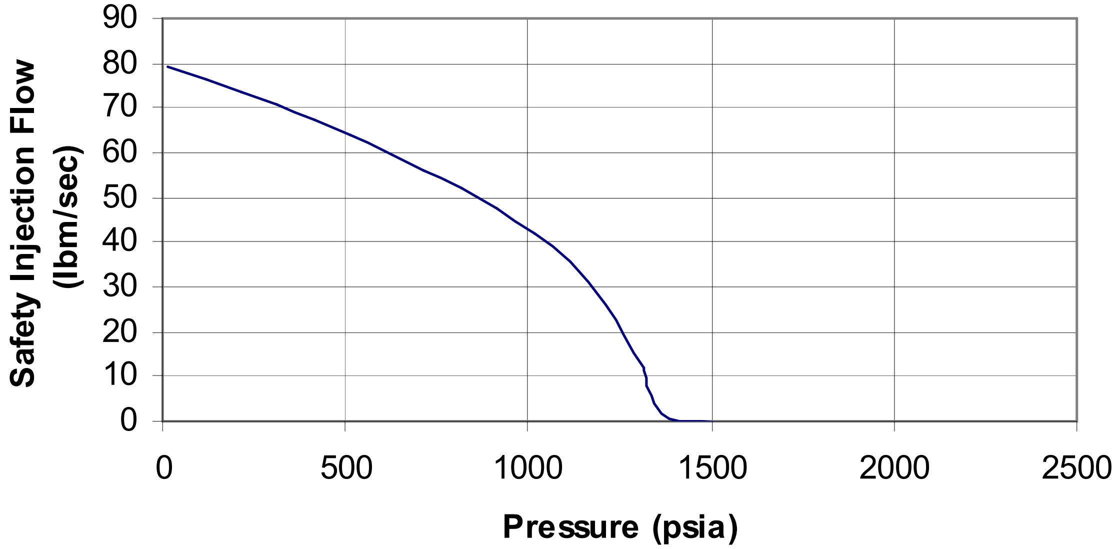


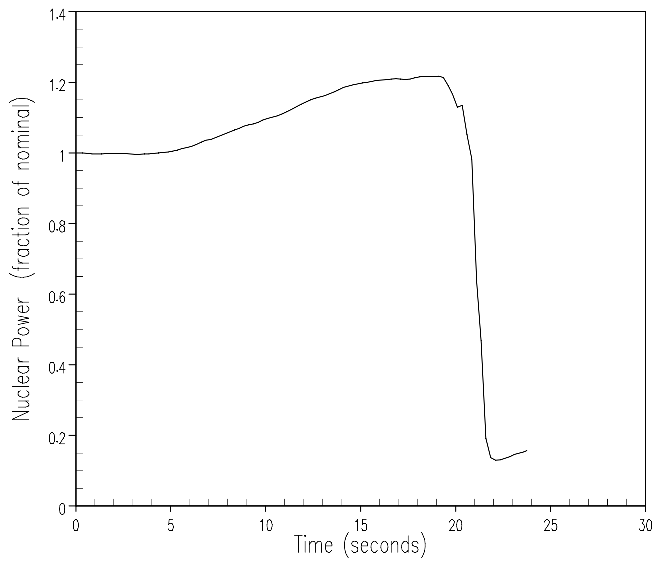
Table 2.8.5.1.2.2.2-1
Time Sequence of Events – Steam System Piping Failure at Full-Power
(Core Response – 0.86 ft^2 break)

Event	Time (sec)
Steam Line Ruptures	0.0
Overpower T Reactor Trip Setpoint Reached	17.25
Rods Begin to Drop	18.75
Minimum DNBR Occurs	19.34
Peak Core Heat Flux Occurs	19.34

Table 2.8.5.1.2.2.2-2
MPS3 HFP SLB Break Spectrum Results

Break Size (ft^2)	Trip Function	Trip Time (Rod Motion) (sec)	Peak Heat Flux (FON)
1.4	SI	4.296	1.00013
0.87	SI	10.790	1.09859
0.86	OPΔT (on Loops 1 and 3)	18.749	1.21050
0.85	OPΔT (on Loops 1 and 3)	18.979	1.20881
0.48	OPΔT (on Loops 1 and 3)	52.045	1.18996
0.47	No Trip	NA	1.19086
0.46	No Trip	NA	1.18732

Figure 2.8.5.1.2.2.2-1
Steam System Piping Failure at Full-Power – 0.86 ft^2 Break
Nuclear Power and Core Heat Flux vs. Time



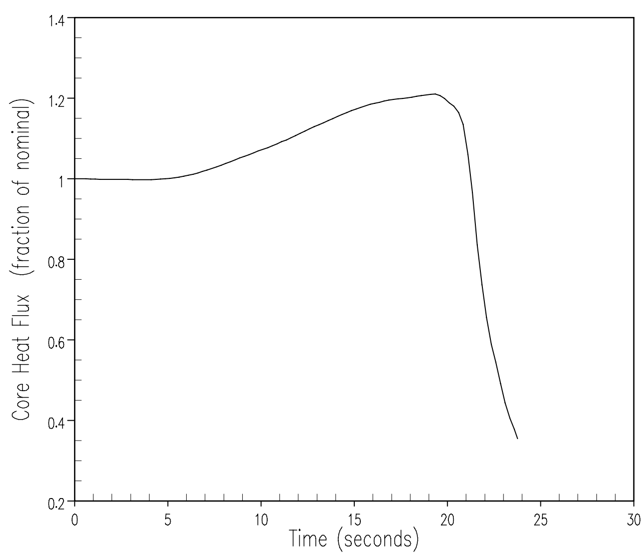
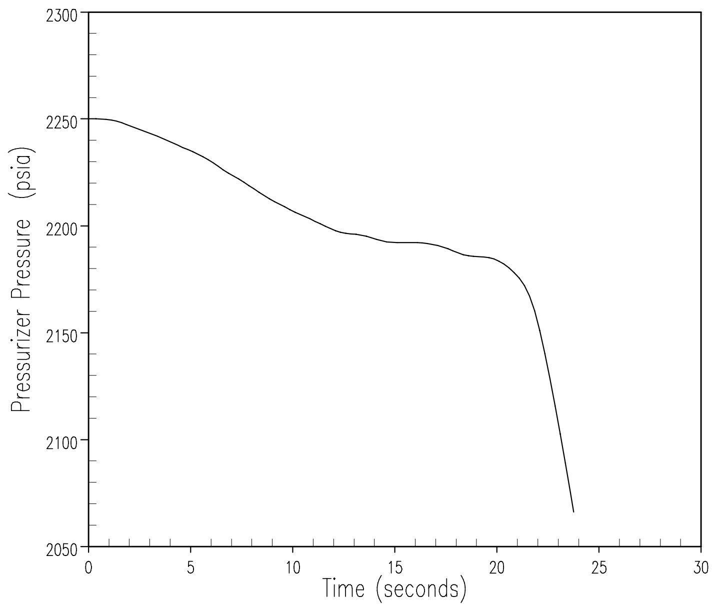


Figure 2.8.5.1.2.2.2-2
Steam System Piping Failure at Full-Power – 0.86 ft^2 Break
Pressurizer Pressure and Pressurizer Water Volume vs. Time



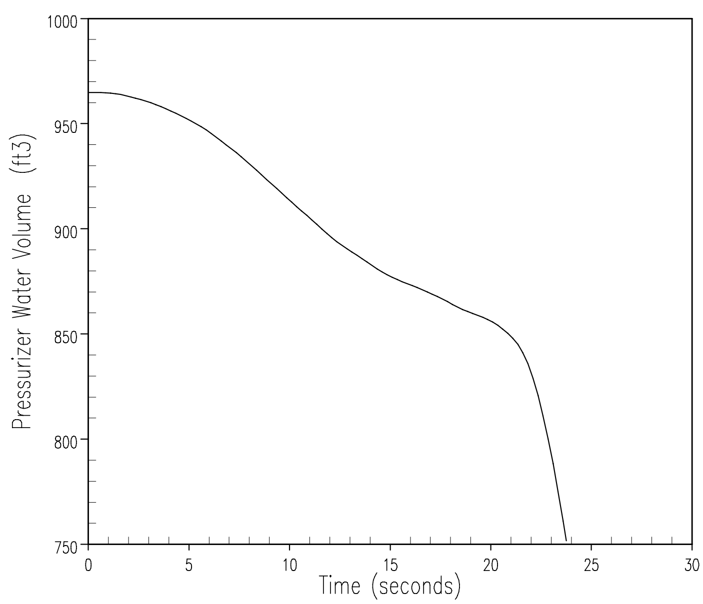


Figure 2.8.5.1.2.2.2-3
Steam System Piping Failure at Full-Power – 0.86 ft² Break
Vessel Inlet Temperature vs. Time

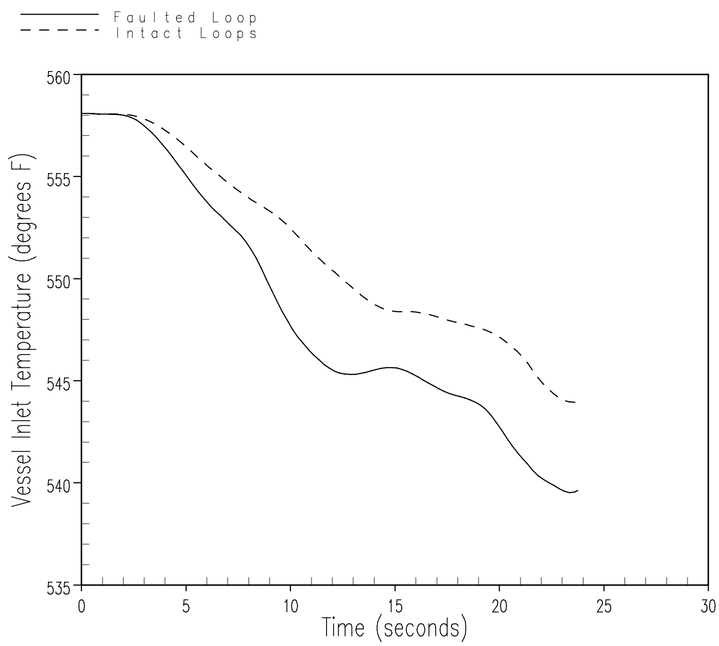
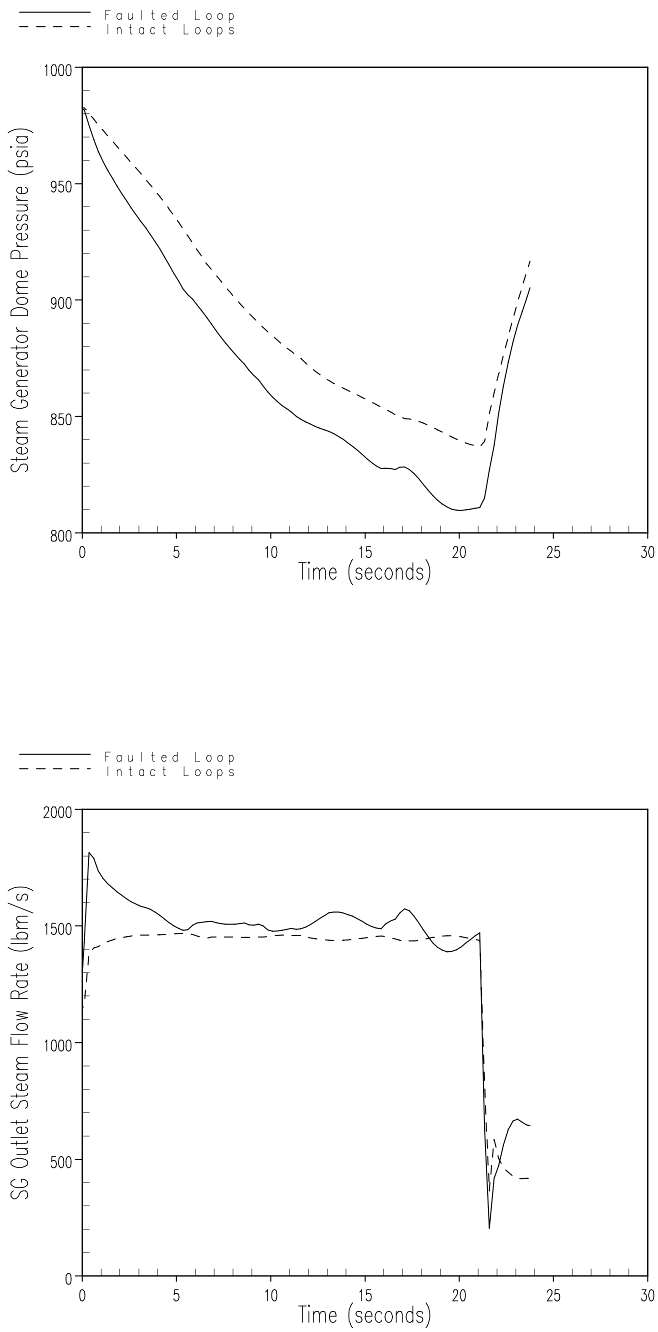


Figure 2.8.5.1.2.2.2-4
Steam System Piping Failure at Full-Power – 0.86 ft^2 Break
Steam Generator Dome Pressure and Steam Generator Outlet Steam Flow Rate vs. Time



2.8.5.2 Decrease in the Heat Removal By the Secondary System

2.8.5.2.1 Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum

2.8.5.2.1.1 Regulatory Evaluation

A number of initiating events may result in unplanned decreases in heat removal by the secondary system. These events result in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transient.

The DNC review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses.

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including anticipated operational occurrences (AOOs)
- GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation
- GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded

Specific review criteria are contained in SRP Section 15.2.1-5, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 15.2.1-5, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3’s design relative to:

- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

  1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of

rod failures. These failures are within the capability of the plant clean up system, and are consistent with plant design bases.

2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

Note that the term “fuel damage” as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-15, Reactor Coolant System Design, is described in FSAR Section 3.1.2.15.

The design pressure and temperature for each component in the reactor coolant and associated auxiliary control and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

Additionally, RCPB components achieve a large margin of safety by the use of proven ASME materials and design codes; the use of proven fabrication techniques; nondestructive shop testing; and integrated hydrostatic testing of assembled components. FSAR Chapter 5 discusses the RCS design.

- GDC-26, Reactivity Control System Redundancy and Capability, is described in FSAR Section 3.1.2.26.

Two reactivity control systems are provided. They are the RCCAs and chemical shim (boric acid). The RCCAs are inserted into the core by the force of gravity.

During operation, the shutdown rod banks are fully withdrawn. The rod control system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specific fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses, and the most reactive rod cluster is assumed to be in the fully withdrawn position.

The CVCS maintains the reactor in the cold shutdown state independent of the position of the control rods. It can compensate for xenon burnout transients.

FSAR Chapter 4 presents details of the construction of the RCCAs. FSAR Chapter 7 discusses their operation. FSAR Chapter 9 describes the means of controlling boric acid concentration. FSAR Chapter 15 includes performance analyses under accident conditions.

FSAR Sections 15.2.2, 15.2.3, and 15.2.5 provide the analyses of the loss of external electrical load, turbine trip, and loss of condenser vacuum, respectively. The loss of external load and turbine trip events are classified as ANS Condition II events. As stated in FSAR Section 15.2.5, loss of condenser vacuum is one of the events that can cause a turbine trip.

Loss of External Electrical Load

FSAR Section 15.2.2.1 concludes that a loss of external load event results in a nuclear steam supply (NSSS) system transient that is less severe than a turbine trip event (FSAR Section 15.2.3). Therefore, a detailed transient analysis is not presented for the loss of external load.

Turbine Trip

For a turbine trip event, the reactor would be tripped directly (unless below the Power Range Neutron Flux Reactor Trip System interlock P-9) from a signal derived from the turbine stop emergency trip fluid pressure and turbine stop valves. The turbine stop valves close rapidly (with a minimum delay time of 0.1 seconds) on loss of trip fluid pressure actuated by a turbine trip signal.

FSAR Table 15.0-2 and Section 15.2.3.2 state that this transient is analyzed with the LOFTRAN code to compute pertinent plant variables including temperatures, pressures, and power level.

FSAR Section 15.2.3.3 concludes that the plant design is such that a turbine trip without a direct or immediate reactor trip presents no hazard to the integrity of the RCS or the main steam system. Pressure relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits. The integrity of the core is maintained by operation of the reactor protection system, i.e., the DNBR is maintained above the safety analysis limit. The DNBR design basis is described in FSAR Section 4.4. Applicable acceptance criteria as listed in FSAR Section 15.0.1 have been met. The analysis demonstrates the ability of the nuclear steam supply system to safely withstand a full load rejection.

Loss-of-Condenser Vacuum

As stated in FSAR Section 15.2.5, loss of condenser vacuum is one of the events that can cause a turbine trip. 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. Therefore, the analysis results and conclusions contained in FSAR Section 15.2.3 (discussed above) apply to loss of condenser vacuum.

Westinghouse NSALs -02-3 Rev. 01; -02-4 Rev. 0 and –02-05 Rev. 01 were reviewed for their impacts on the current licensing basis regarding these transients. These NSALs do not impact the transients discussed in this section.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.2.1.2 Technical Evaluation

2.8.5.2.1.2.1 Introduction

A major load loss on the plant can result from either a loss-of-external-electrical load or from a turbine trip. A loss-of-external-electrical load can result from an abnormal variation in network frequency or other adverse network operating condition. In either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps (RCPs).

The plant is designed to accept a 50 percent loss-of-electrical load while operating at full power, or a complete loss of load while operating below the P-9 setpoint without actuating a reactor trip with all NSSS control systems in automatic (addressed in Section 2.4.2). A 50 percent loss-of-electrical load is handled by the steam dump system, the rod control system, and the pressurizer (which absorbs the change in coolant volume due to the heat addition resulting from the load rejection). Should a complete loss of load occur from full power, the reactor trip system automatically actuates a reactor trip.

The most likely source of a complete loss of load on the NSSS is a trip of the turbine generator (turbine trip). In this case, there is a direct reactor trip signal derived from either the turbine auto-stop oil pressure or closure of the turbine stop valves, provided the reactor is operating above the P-9 setpoint. Reactor temperature and pressure do not increase significantly if the steam dump system and pressurizer pressure control system are functioning properly. However, the RCS and main steam system (MSS) pressure-relieving capacities are designed to ensure the safety of the plant without requiring the use of automatic rod control, pressurizer pressure control, and/or steam dump control systems. In this analysis, the behavior of the plant is evaluated for a complete loss-of-steam load from full power without direct reactor trip in order to demonstrate the adequacy of the pressure-relieving devices and core protection margins.

In the event the steam dump valves fail to open following a large loss-of-load, the main steam safety valves (MSSVs) can lift and the reactor can be tripped by the high pressurizer pressure signal, the overtemperature ΔT signal, or the overpower ΔT signal. The steam generator shell-side pressure and reactor coolant temperatures increase rapidly. The pressurizer safety valves (PSVs) and MSSVs 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, pressurizer power-operated relief valves (PORVs), automatic rod control, or the direct reactor trip on turbine trip.

For this group of events, the primary side transient is caused by a decrease in heat transfer capability from primary to secondary due to a rapid termination of steam flow to the turbine, accompanied by an automatic reduction of feedwater flow (should feed flow not be reduced, a larger heat sink would be available and the transient would be less severe). Termination of steam flow to the turbine following a loss of external load occurs due to automatic fast closure of the turbine control valves. Following a turbine trip event, termination of steam flow occurs via turbine stop valve closure which occurs more rapidly than closure of the turbine control valves.

Therefore, the transient in primary pressure, temperature, and water volume is less severe for the loss of external load than for the turbine trip event due to a slightly slower loss of heat transfer capability. Therefore, only the turbine trip event was specifically analyzed for the SPU. The loss of condenser vacuum is one event that could cause a turbine trip, and would preclude the use of steam dump to the condenser. However, the turbine trip analysis described below, does not credit steam dump. Therefore, the results and conclusions of this analysis apply to the loss of condenser vacuum event and are bounding for the loss of external load event.

2.8.5.2.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Three cases were analyzed for a turbine trip from full-power SPU conditions:

- With automatic pressure control (DNBR case)
- With automatic pressure control, minimum steam generator tube plugging (SGTP) and zero steam generator tube fouling (MSS pressure case)
- Without automatic pressure control (RCS pressure case)

The primary concern for the case analyzed with pressure control is the minimum DNBR. The primary concern for the case analyzed with pressure control, minimum SGTP, and zero steam generator tube fouling was maintaining MSS pressure below 110 percent of the secondary side design pressure. The primary concern for the case analyzed without pressure control was maintaining RCS pressure below 110 percent of the primary side design pressure.

The DNBR case was analyzed using the revised thermal design procedure (RTDP) (Reference 1). NSSS power, RCS temperature and pressure were assumed to be at their nominal values consistent with steady-state, full-power operation. Minimum measured flow was modeled. Uncertainties in initial conditions were included in the DNBR limit as described in Reference 1.

The RCS and MSS peak pressure cases were analyzed using the standard thermal design procedure (STDP). Initial uncertainties on NSSS power, RCS temperature, and pressure were applied in the conservative direction to obtain the initial plant conditions for the transient. Both cases modeled thermal design flow.

The turbine trip transient was analyzed conservatively with minimum reactivity feedback (beginning of core life). All cases assumed the least-negative Doppler power coefficient and a 0 pcm/°F moderator temperature coefficient, which bounded part-power conditions, assuming a positive moderator temperature coefficient. Minimum reactivity conditions were conservative since reactor power was maintained until the time of reactor trip, which exacerbated the calculated minimum DNBR and maximum RCS and MSS pressures.

Manual rod control was modeled for all cases. If the reactor had been in automatic rod control, the control rod banks would have driven into the core prior to reactor trip, thereby reducing the severity of the transient.

The turbine trip event was analyzed both with and without pressurizer pressure control. The pressurizer PORVs and sprays were assumed operable for the DNBR case to minimize the increase in primary pressure, which was conservative for the DNBR criterion. The pressurizer

PORVs and sprays were assumed operable for the MSS peak pressure case to minimize the increase in primary pressure, which delayed reactor trip, resulting in a conservatively high calculated peak secondary side pressure. The RCS pressure case was analyzed without pressure control to conservatively maximize the RCS pressure increase. In all cases, the MSSVs and pressurizer safety valves were operable.

A total PSV setpoint tolerance of -3 percent/+3 percent was modeled in the analysis. For the DNBR case and MSS peak pressure case, the negative tolerance was applied to conservatively reduce the setpoint. For the RCS peak pressure case, the positive tolerance was applied to conservatively increase the setpoint pressure.

Main feedwater flow to the steam generators was assumed to be lost at the time of turbine trip. The auxiliary feedwater system is modeled, however, the low-low steam generator setpoint is not reached to initiate auxiliary feedwater flow.

The following reactor trip setpoints are assumed to be operable:

- Reactor trip on high pressurizer pressure
- Reactor trip on overtemperature ΔT
- Reactor trip on overpower ΔT
- Reactor trip on low-low steam generator water level

The MSSV model for all cases includes a 3 percent setpoint tolerance and an accumulation model that assumes that the safety valves are wide open once the pressure exceeds the setpoint (plus tolerance) by 5 psi.

The limiting single failure is failure of one train of the reactor trip system. The remaining (operable) train trips the reactor. As described in FSAR Section 3.1.1, the MSSVs and pressurizer safety valves (i.e., code safety valves) are considered especially qualified active components and are assumed to open on demand. Control systems are not assumed to operate abnormally during a transient except as an initial condition (e.g., a Feedwater Malfunction event). Thus, a failure of a control system is not applicable as a limiting single failure. Feedwater isolation (redundant valves with different closure times), auxiliary feedwater (multiple pumps) and safety injection (multiple pumps) are susceptible to a single failure. However, none of these systems provide any mitigation for a turbine trip event. Thus, these systems are not applicable as a limiting single failure. Furthermore, the protection system is designed to be single failure proof.

Maximum (10 percent) steam generator tube plugging is assumed in the DNBR case and RCS peak pressure case since it maximizes the RCS temperature transient following event initiation. However, the MSS peak pressure case is analyzed at zero steam generator tube plugging and zero steam generator tube fouling since this conservatively maximizes the initial steam generator pressure (i.e., the initial pressure is closer to the MSSV opening setpoint). This assumption is slightly more limiting with respect to the secondary side pressure transient.

Based on its frequency of occurrence, the turbine trip accident is considered a Condition II event as defined by the American Nuclear Society. The specific criteria for this accident, as stated in the Standard Review Plan (SRP), are as follows:

- Pressure in the reactor coolant and main steam systems are maintained below 110 percent of the design values (an RCS pressure limit of 2750 psia and secondary side pressure limit of 1320 psia).
- Fuel cladding integrity is maintained by demonstrating that the minimum DNBR remains above the 95/95 DNBR limit for PWRs (the applicable safety analysis DNBR limit is 1.60).
- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently.

  This criterion is satisfied by verifying that the pressurizer does not fill.
- An incident of moderate frequency in combination with any single active component failure, or single operator error, is considered an event for which an estimate of the number of potential fuel failures is provided for radiological dose calculations. For such accidents, fuel failure is assumed for all rods for which the DNBR falls below those values cited above for cladding integrity unless it can be shown that, based on an acceptable fuel damage model, fewer failures occur. There is no loss of function of any fission product barrier other than the fuel cladding.

  This criterion is satisfied by verifying that the DNBR remains above the 95/95 DNBR limit.

2.8.5.2.1.2.3 Description of Analyses and Evaluations

For the turbine trip event, the behavior of the unit was analyzed for a complete loss of steam load from full power without a direct reactor trip for the SPU conditions.

A detailed analysis using the RETRAN (Reference 2) computer code was performed to determine the plant transient conditions following a total loss of load due to turbine trip. The code models the core neutron kinetics, RCS, pressurizer, pressurizer PORVs and sprays, steam generators, MSSVs, and the auxiliary feedwater system. RETRAN computes pertinent variables, including the pressurizer pressure, steam generator pressure, and reactor coolant average temperature.

This computer code is different than that used for the current licensing basis analysis where the LOFTRAN code is used. RETRAN has been approved by the NRC for the analysis of loss of load/turbine trip transients (Reference 2). The applicability of RETRAN to MPS3 for the SPU is addressed in Section 2.8.5.0.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the loss of load/turbine trip analysis. As stated in Section 2.8.5.2.1.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.2.1.2.4 Results

The time sequence of events for each of the three turbine trip cases is presented in Table 2.8.5.2.1-1. Numerical results of the SPU analysis along with a comparison to the previous analysis results are shown in Table 2.8.5.2.1-2.

With respect to DNBR, the SPU analysis provides more limiting results than the previous analysis. However, with respect to RCS and MSS peak pressure, the SPU analyses are less limiting than the previous analyses. This is due to the overly-conservative assumption of 3 percent accumulation (~77 psi) for the PSV in the previous analyses. Based on extensive testing of spring-loaded safety valves, as discussed in WCAP-12910 (Reference 3), once a spring-loaded safety valve reaches the point of first stem movement, the valve very rapidly 'pops' wide open relieving at full capacity. As such, the valve not only experiences stem movement at the valve setpoint, which is based on first stem movement and must be within the setpoint tolerance of the Tech Spec setpoint, but the valve is fully open at this pressure. Therefore, any accumulation experienced by the valve occurs during the pressurization phase prior to the valve 'pop'. The lower RCS and MSS peak pressures resulting from the SPU analyses are a result of modeling full capacity PSV relief once the valve setpoint is reached, as compared to the previous analyses which modeled 3 percent PSV accumulation.

DNBR Case

The transient response plot results for the turbine trip event (DNBR case) are shown in Figures 2.8.5.2.1-1 through 2.8.5.2.1-3. The reactor was tripped on the high-pressurizer pressure reactor trip function. The nuclear power increased slightly until the reactor was tripped and the pressurizer PORVs, safety valves and sprays minimized the primary pressure transient, which was conservative for DNBR. Although the DNBR decreased below the initial value, it remained well above the safety analysis limit throughout the entire transient. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition. The MSSVs actuated to maintain the secondary side pressure below 110 percent of the design value.

MSS Peak Pressure Case

The transient response plot results for the turbine trip event (MSS peak pressure case) are shown in Figures 2.8.5.2.1-4 through 2.8.5.2.1-6. The reactor was tripped on the high-pressurizer pressure reactor trip function. The nuclear power remained essentially constant at full power until the reactor was tripped and the pressurizer PORVs, safety relief valves and sprays minimized the primary pressure transient, which was conservative to delay reactor trip and exacerbate the peak secondary side pressure. The MSSVs actuated to maintain the secondary side pressure below 110 percent of the design value. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition.

RCS Peak Pressure Case

The transient response plot results for the turbine trip event (RCS peak pressure case) are shown in Figures 2.8.5.2.1-7 through 2.8.5.2.1-9. The reactor was tripped on the high-pressurizer pressure reactor trip function. The nuclear power remained essentially constant at full power until the reactor was tripped. The PSVs actuated and confirmed that the primary side pressure was maintained below 110 percent of the design value. The MSSVs also actuated and maintained the secondary side pressure below 110 percent of the design value. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition.

2.8.5.2.1.3 Conclusion

DNC has reviewed the analyses of the decrease in heat removal events described above and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -10, -15, and -26 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the events stated.

2.8.5.2.1.4 References

1. WCAP-11397-P-A, “Revised Thermal Design Procedure,” April 1989.

2. WCAP-14882-P-A, “RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses,” April 1999.

3. WCAP-12910-P, Rev. 1-A, “Pressurizer Safety Valve Set Pressure Shift,” May 1993.

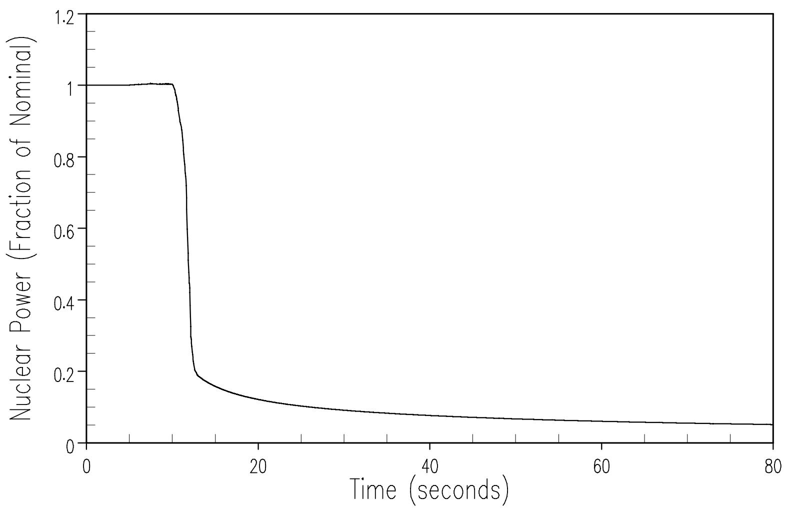
Table 2.8.5.2.1-1
Time Sequence of Events –Turbine Trip

Case	Event	Time into Transient (sec)
DNBR Case (auto pressurizer pressure control, RTDP initial conditions)	Turbine Trip	0.0
	High-Pressurizer Pressure Reactor Trip Setpoint Reached	7.4
	Rods Begin to Drop	9.4
	Minimum DNBR Occurs	10.9
MSS Peak Pressure Case (auto pressurizer pressure control, STDP initial conditions)	Turbine Trip	0.0
	High-Pressurizer Pressure Reactor Trip Setpoint Reached	8.0
	Rods Begin to Drop	10.0
	Peak Secondary Side Pressure Occurs	15.2
RCS Peak Pressure Case (no pressurizer pressure control, STDP initial conditions)	Turbine Trip	0.0
	High-Pressurizer Pressure Reactor Trip Setpoint Reached	6.2
	Rods Begin to Drop	8.2
	Peak RCS Pressure Occurs	9.9

Table 2.8.5.2.1-2
Turbine Trip – Results and Comparison to Previous Results

	SPU Analysis	Previous Analysis	Limit
Minimum DNBR	2.10	2.51	1.60 (SPU)
Peak Primary System Pressure (psia)	2729.41	2731.0	2750.0
Peak Secondary System Pressure (psia)	1302.25	1319.6	1320.0

Figure 2.8.5.2.1-1
Turbine Trip DNBR Case Nuclear Power and Steam Generator Pressure vs. Time



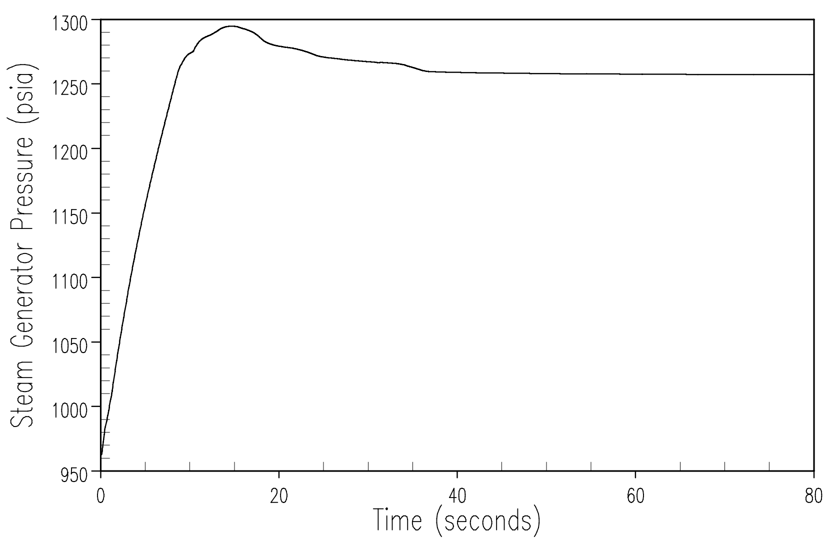
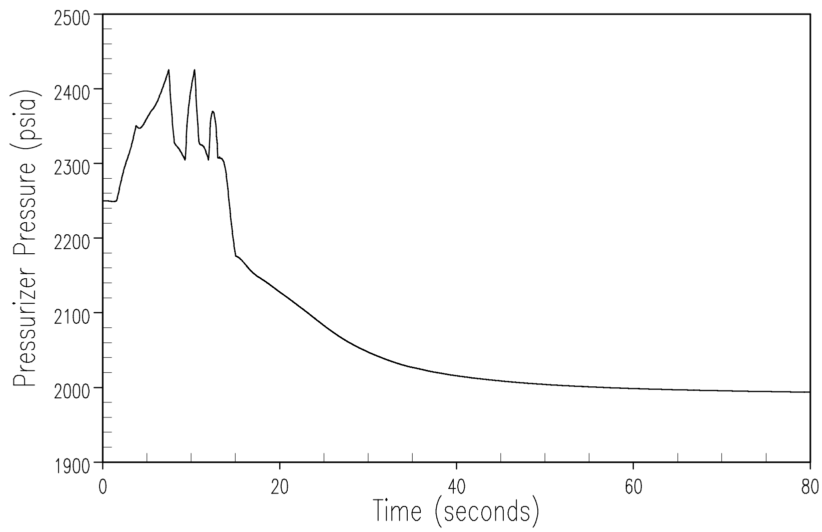


Figure 2.8.5.2.1-2
Turbine Trip DNBR Case Pressurizer Pressure and Pressurizer Water Volume vs. Time



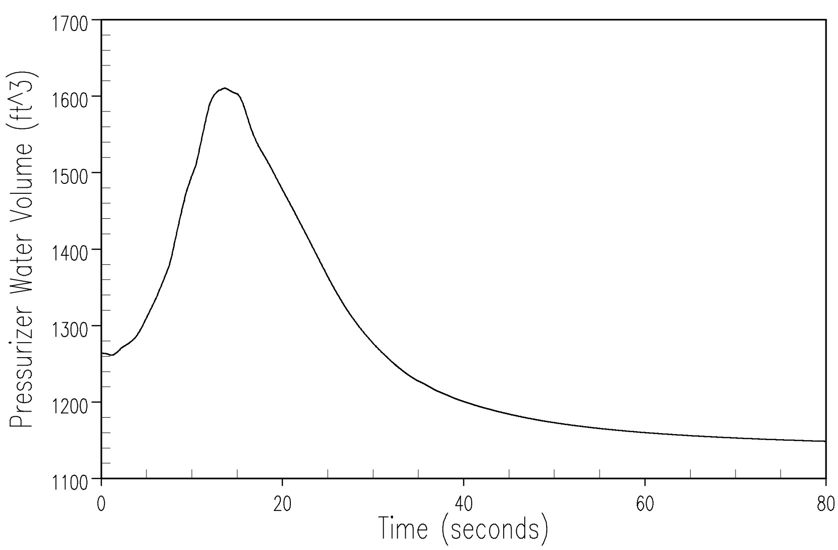
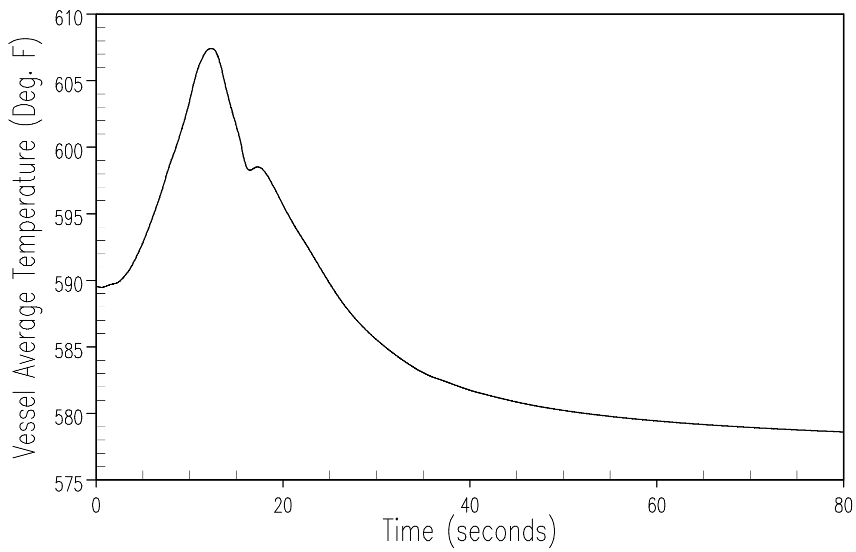


Figure 2.8.5.2.1-3
Turbine Trip DNBR Case Vessel Average Temperature and DNBR vs. Time



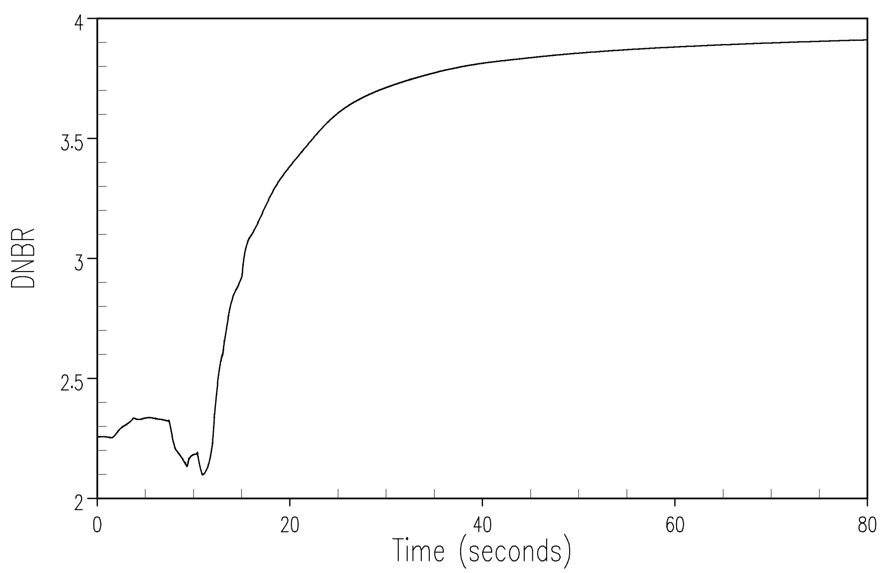
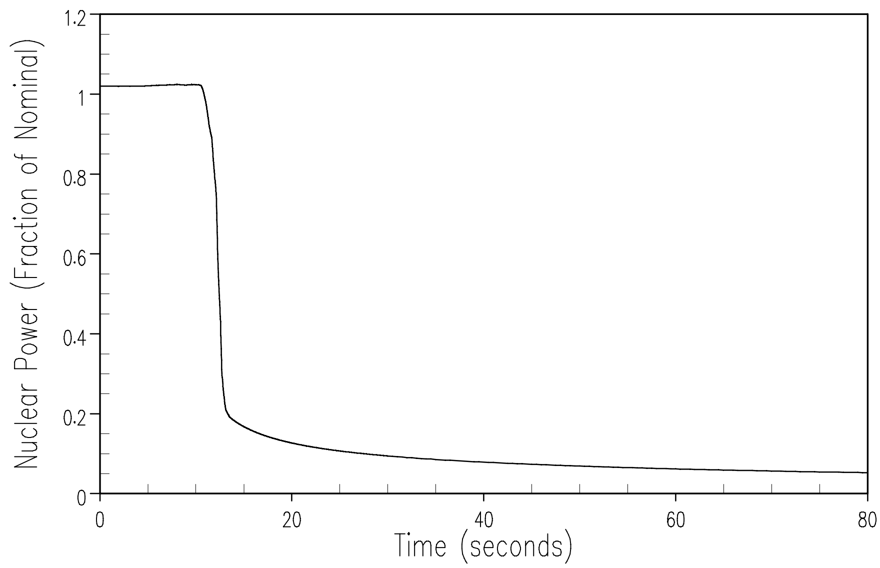


Figure 2.8.5.2.1-4
Turbine Trip MSS Peak Pressure Case Nuclear Power and Steam Generator Pressure vs. Time



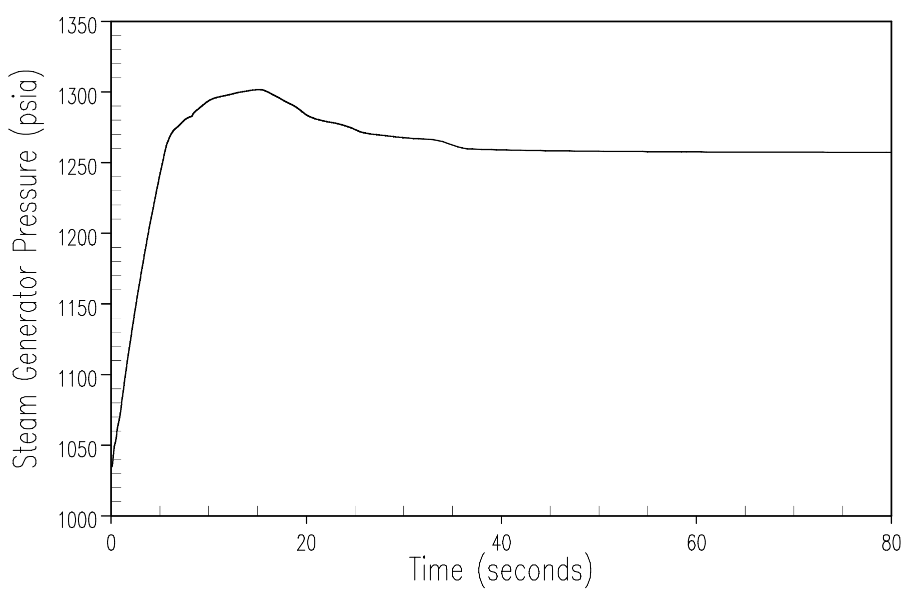
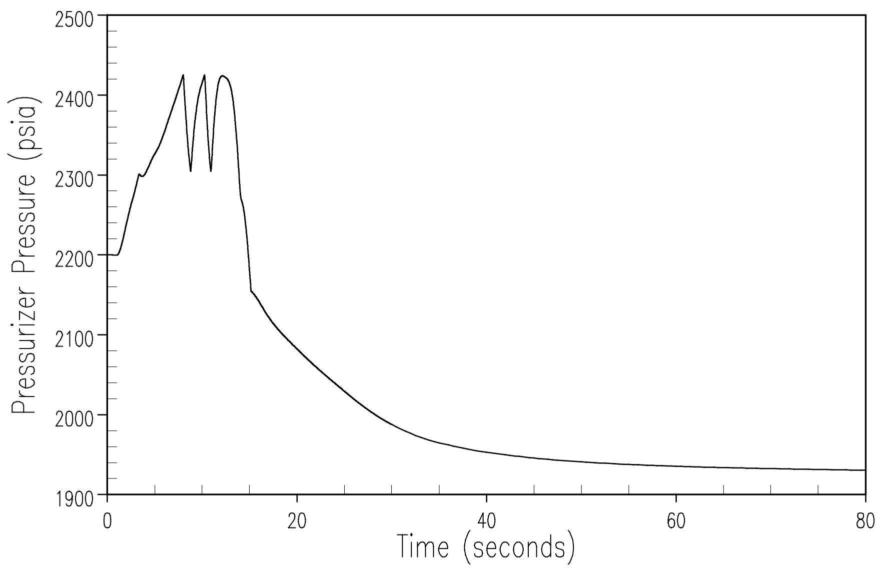


Figure 2.8.5.2.1-5
Turbine Trip MSS Peak Pressure Case Pressurizer Pressure and Pressurizer Water Volume vs. Time



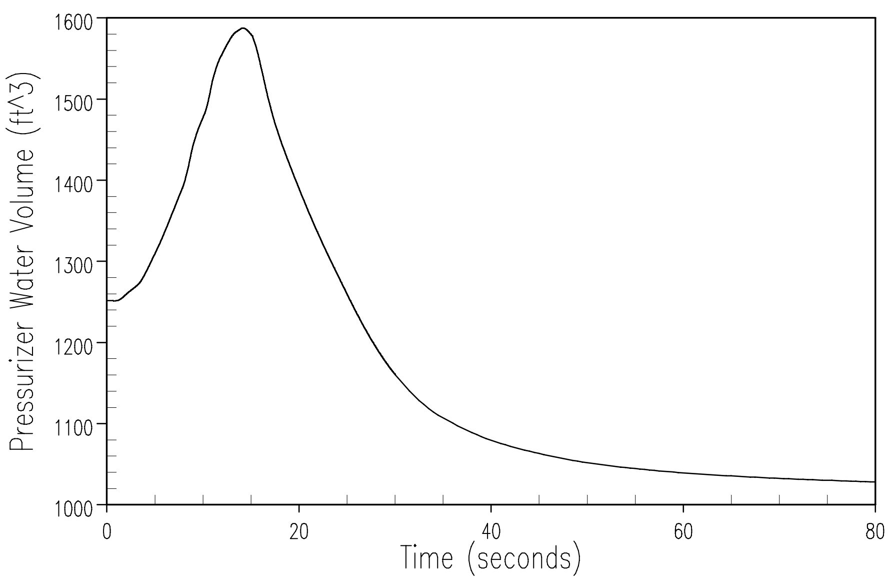


Figure 2.8.5.2.1-6
Turbine Trip MSS Peak Pressure Case Vessel Average Temperature vs. Time

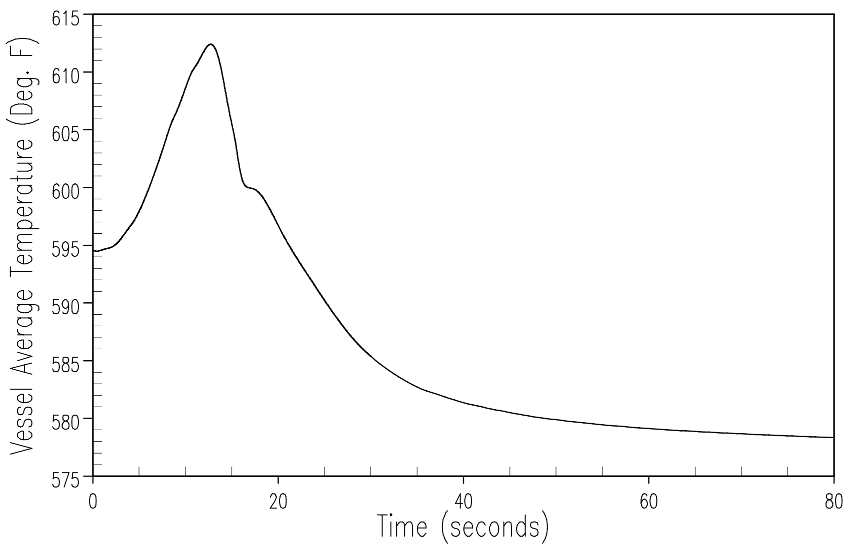
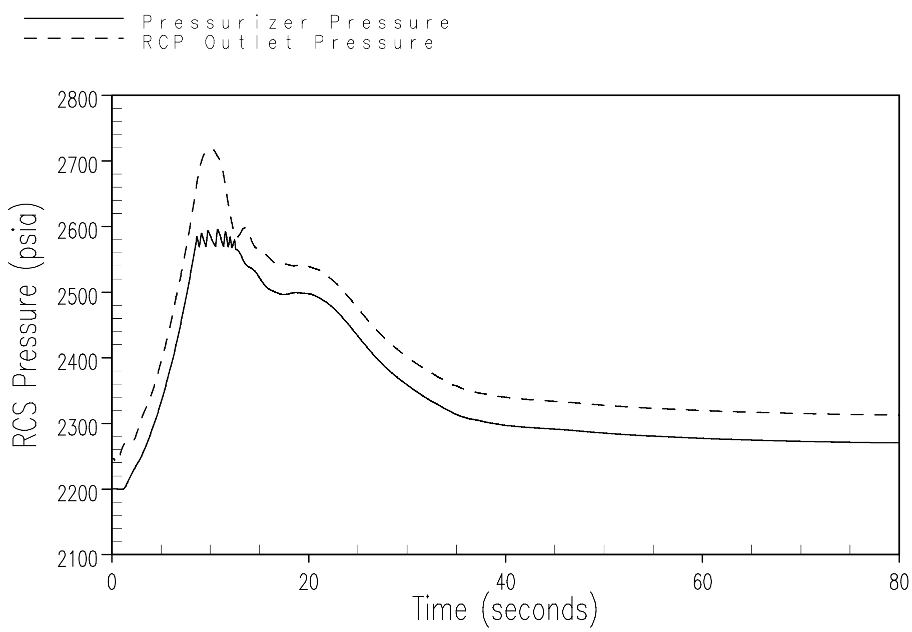


Figure 2.8.5.2.1-7
Turbine Trip RCS Peak Pressure Case RCS Pressure and Pressurizer Water Volume vs. Time



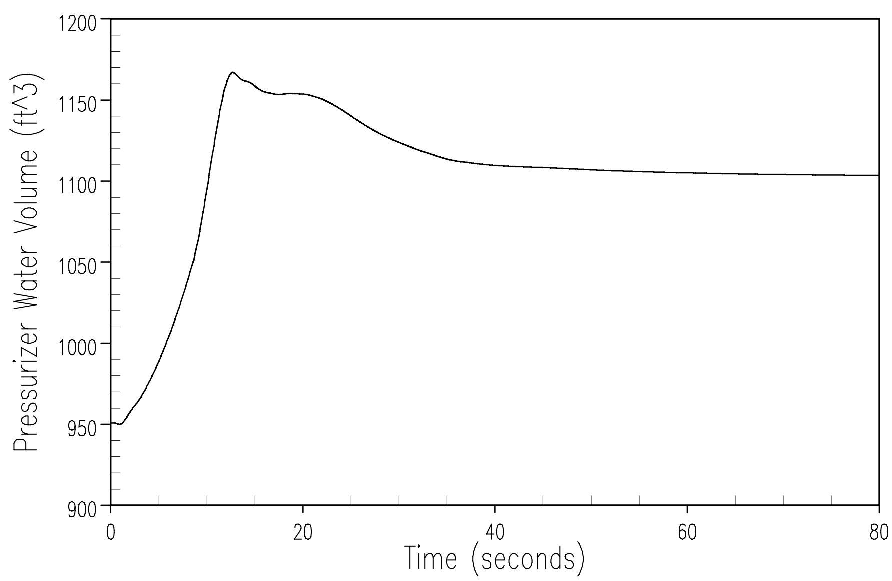
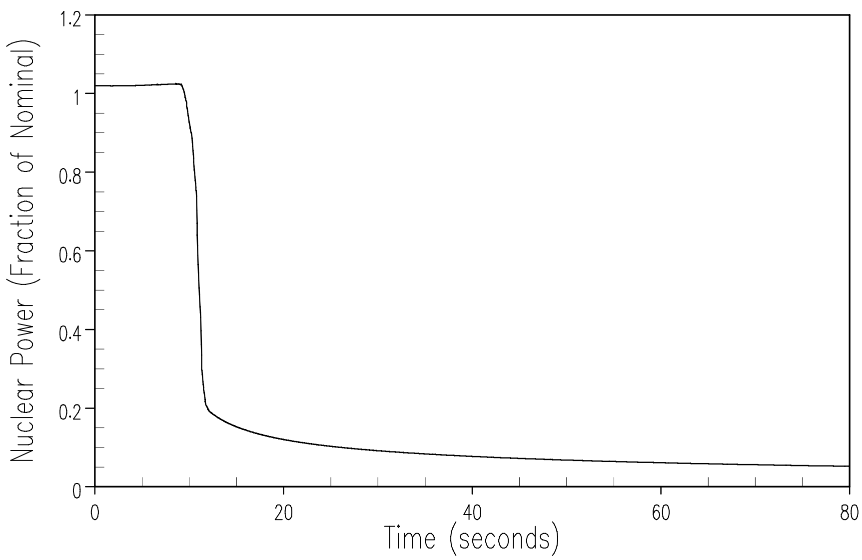


Figure 2.8.5.2.1-8
Turbine Trip RCS Peak Pressure Case Nuclear Power and Steam Generator Pressure vs. Time



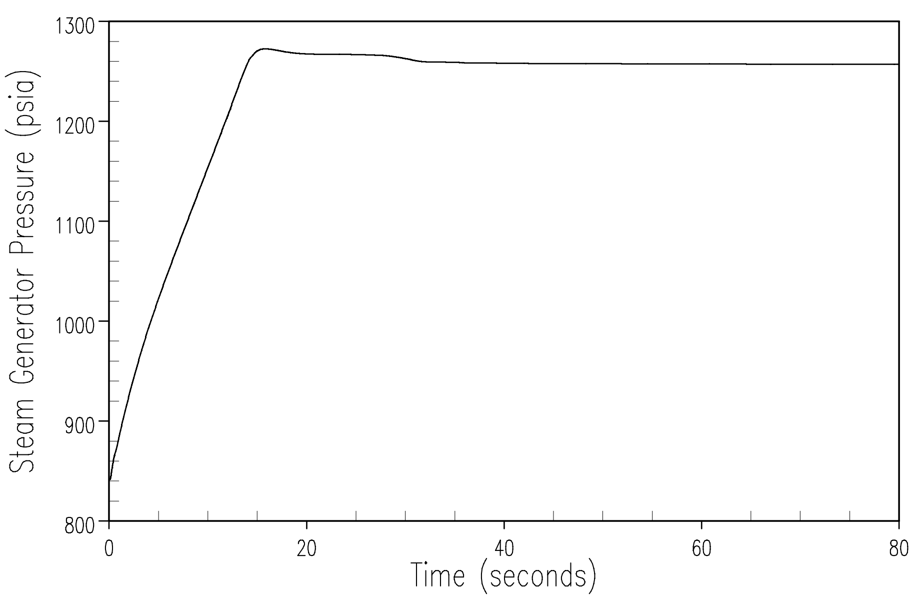
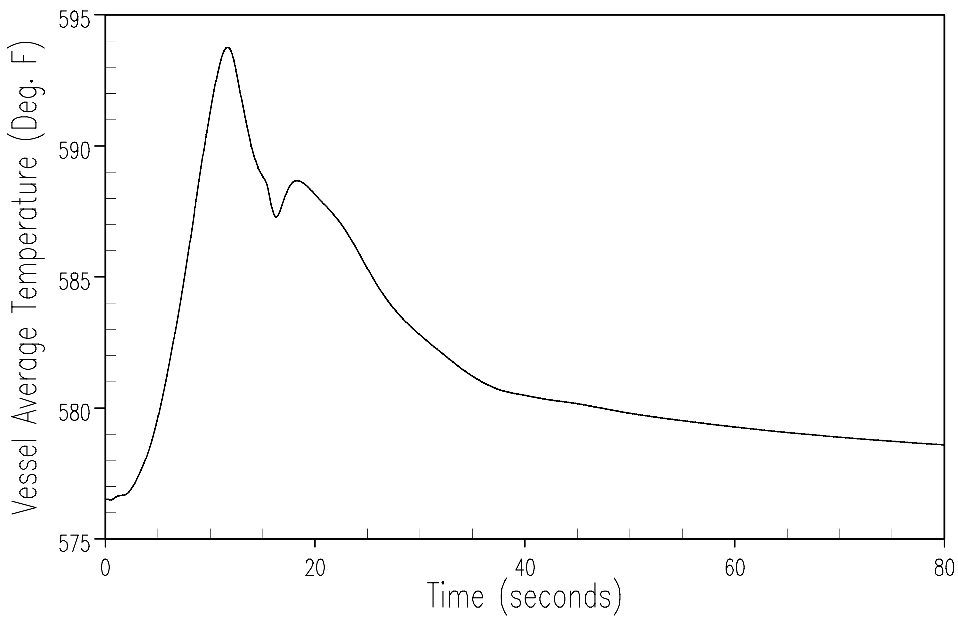


Figure 2.8.5.2.1-9
Turbine Trip RCS Peak Pressure Case Vessel Average Temperature vs. Time



2.8.5.2.2 Loss of Non-Emergency AC Power to the Station Auxiliaries

2.8.5.2.2.1 Regulatory Evaluation

The loss of non-emergency AC power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all RCPs. This causes a flow coastdown as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient.

The DNC review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses.

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including anticipated operational occurrences (AOOs)
- GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation
- GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded

Specific review criteria are contained in SRP Section 15.2.6, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 15.2.6, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3’s design relative to:

- GDC-10, Reactor design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

  1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of

rod failures. These failures are within the capability of the plant clean up system, and are consistent with plant design bases.

2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

Note that the term “fuel damage” as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-15, Reactor Coolant System Design, is described in FSAR Section 3.1.2.15.

The design pressure and temperature for each component in the reactor coolant and associated auxiliary, control and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

Additionally, RCPB components achieve a large margin of safety by the use of proven ASME materials and design codes; the use of proven fabrication techniques; nondestructive shop testing; and integrated hydrostatic testing of assembled components. FSAR Chapter 5 discusses the RCS design.

- GDC-26, Reactivity Control System Redundancy and Capability, is described in FSAR Section 3.1.2.26.

Two reactivity control systems are provided. They are the RCCAs and chemical shim (boric acid). The RCCAs are inserted into the core by the force of gravity.

During operation, the shutdown rod banks are fully withdrawn. The rod control system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specific fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses, and the most reactive rod cluster is assumed to be in the fully withdrawn position.

The CVCS maintains the reactor in the cold shutdown state independent of the position of the control rods. It can compensate for xenon burnout transients.

FSAR Chapter 4 presents details of the construction of the RCCAs. FSAR Chapter 7 discusses their operation. FSAR Chapter 9 describes the means of controlling boric acid concentration.

FSAR Section 15.2.6 addresses the impact of a loss of non-emergency AC power to the station auxiliaries. A complete loss of non-emergency AC power may result in a loss of all power to the station auxiliaries, i.e., the RCPs, condensate pumps, etc. The loss of power may be caused by a complete loss of the offsite grid accompanied by a turbine generator trip at the station, or by a loss of the onsite AC distribution system. This event is classified as an ANS Condition II event.

Upon loss of power to the RCPs, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the reactor coolant loops. FSAR Section 15.2.6.3 concludes that analysis of the natural circulation capability of the RCS has demonstrated that sufficient heat removal capability exists following RCP coastdown to prevent fuel or clad damage.

Westinghouse NSALs 02-3 Rev. 01; 02-4, Rev. 0; and 02-5 Rev 01 identified potential non-conservative errors in SG level measurement due to the pressure drop across the SG mid deck plate; potential impacts on the SG level reactor trip setpoints; and potential impacts to SG water level control system uncertainties utilized as initial condition assumptions for SG water level related safety analyses. DNC implemented modifications to the MPS3 narrow range SG level measurement instrument loops during 3R11 (April, 2007) to address changes in instrument uncertainties for level control and setpoints used for SG low-low level reactor trip.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.2.2.2 Technical Evaluation

2.8.5.2.2.2.1 Introduction

A complete loss of non-emergency AC power (FSAR 15.2.6) results in a loss of power to the plant auxiliaries, i.e., the RCPs, main feedwater pumps, condensate pumps, etc. The loss-of-power can be caused by a complete loss-of-the-offsite grid accompanied by a turbine generator trip at the station, or by a loss-of-the-onsite-AC distribution system. The events following a loss-of-AC power with turbine and reactor trip are described in the sequence listed below:

- Plant vital instruments are supplied by emergency DC power sources.
- The main steam pressure relieving valves may be automatically opened to the atmosphere as the steam system pressure rises following the trip. The condenser is assumed unavailable for steam dump. If the relief capacity of the main steam pressure relieving valves is inadequate, the main steam safety valves (MSSVs) can lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

- The main steam pressure relieving valves (or MSSVs, if the main steam pressure relieving valves are unavailable) are used to dissipate the residual decay heat and to maintain the plant at the MODE 3 (hot shutdown) condition as the no-load temperature is approached.
- The emergency diesel generators start on loss of voltage to plant emergency buses and begin to supply plant vital loads.

The auxiliary feedwater system is started automatically as follows:

- Two motor-driven auxiliary feedwater (MDAFW) pumps are started on any of the following:
  - Low-low water level in two-out-of-four level channels in any steam generator
  - Safety injection
  - Loss of offsite power
  - Manual actuation
  - AMSAC actuation signal
- One turbine-driven auxiliary feedwater (TDAFW) pump is started on any of the following:
  - Low-low water level in two-out-of-four channels in any two of four steam generators
  - Manual actuation
  - AMSAC actuation

Following the loss of power to the RCPs, heat removal is maintained by natural circulation in the RCS loops. Following the RCP coastdown, the natural circulation capability of the RCS removes decay heat from the core, aided by the AFW flow in the secondary system. Demonstrating that acceptable results can be obtained for this event proves that the resultant natural circulation flow in the RCS is adequate to remove decay heat from the core.

2.8.5.2.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

This event is considered to be bounded by other events as described below, therefore there are no explicit input parameters or assumptions.

Based on its frequency of occurrence, the loss-of-non-emergency-AC-power accident is a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit.
- Pressures in the RCS and main steam system (MSS) are maintained below 110 percent of the design pressures.
- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently.

The first few seconds after a loss-of-AC-power to the RCPs closely resembles the analysis of the complete loss-of-flow event (see Section 2.8.5.3.1) in that the RCS experiences a rapid flow reduction transient. This aspect of the loss-of-AC-power event is bounded by the analysis performed for the complete loss-of-flow event that demonstrates that the DNB design basis is met. With respect to overpressurization of the primary and secondary sides, this event is bounded by the loss of load/turbine trip event (see Section 2.8.5.2.1).

The analysis of the loss of normal feedwater event with loss-of-AC-power (see Section 2.8.5.2.3) demonstrates that RCS natural circulation and the AFW system are capable of removing the stored and residual heat. The plant is therefore able to return to a safe condition. A restrictive acceptance criterion; that the pressurizer does not become water solid was used for this event. This criterion establishes the acceptable capacity of the AFW system, ensuring that the pressure criteria and minimum DNBR criterion remained satisfied for the long-term portion of the event, and demonstrated that a more serious plant condition is precluded.

2.8.5.2.2.2.3 Description of Analyses and Evaluations

As noted above, this event is bounded by events described in other sections of this Licensing Report, therefore, no explicit analyses were performed.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the loss of non-emergency AC power analysis. As stated in Section 2.8.5.2.2.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.2.2.2.4 Results

As noted above, this event is bounded by events described in other sections of this Licensing Report, therefore, no explicit results are reported here. In addition, the transient response of the RCS following a loss-of-AC-power is less severe than for the loss of normal feedwater with a loss of offsite power event reported in Section 2.8.5.2.3.2.4. Those results demonstrate that the available natural circulation flow is sufficient to provide adequate core decay heat removal following reactor trip and reactor coolant pump coastdown.

2.8.5.2.2.3 Conclusion

DNC has reviewed the analyses of the loss of nonemergency ac power to station auxiliaries event and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -10, -15, and -26 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the loss of nonemergency ac power to station auxiliaries event.

2.8.5.2.3 Loss of Normal Feedwater Flow

2.8.5.2.3.1 Regulatory Evaluation

A loss of normal feedwater flow (LONF) could occur from pump failures, valve malfunctions, or a loss of offsite power (LOOP). Loss of feedwater flow results in an increase in reactor coolant temperature and pressure that eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a LONF. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient.

The DNC review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses.

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any normal operations, including anticipated operational occurrences (AOOs)
- GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation
- GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded

Specific review criteria are contained in SRP Section 15.2.7, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 15.2.7, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to:

- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

  1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of

rod failures. These failures are within the capability of the plant clean up system, and are consistent with plant design bases.

2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

Note that the term “fuel damage” as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-15, Reactor Coolant System Design, is described in FSAR Section 3.1.2.15.

The design pressure and temperature for each component in the reactor coolant and associated auxiliary, control and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

Additionally, RCPB components achieve a large margin of safety by the use of proven ASME materials and design codes; the use of proven fabrication techniques; nondestructive shop testing; and integrated hydrostatic testing of assembled components. FSAR Chapter 5 discusses the RCS design.

- GDC-26, Reactivity Control System Redundancy and Capability, is described in FSAR Section 3.1.2.26.

Two reactivity control systems are provided. They are the RCCAs and chemical shim (boric acid). The RCCAs are inserted into the core by the force of gravity.

During operation, the shutdown rod banks are fully withdrawn. The rod control system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specific fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses, and the most reactive rod cluster is assumed to be in the fully withdrawn position.

The CVCS maintains the reactor in the cold shutdown state independent of the position of the control rods. It can compensate for xenon burnout transients.

FSAR Chapter 4 presents details of the construction for the RCCAs. FSAR Chapter 7 discusses their operation. FSAR Chapter 9 describes the means of controlling boric acid concentration.

FSAR Section 15.2.7.1 addresses the impact of a loss of feedwater flow. It states that a loss of normal feedwater (from pump failures, valve malfunctions, or loss of offsite AC power) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If an alternative supply of feedwater were not supplied to the plant, core residual heat following the reactor trip would heat the primary system to the point where water relief from the pressurizer would occur, resulting in a substantial loss of water from the RCS. Since the plant is tripped well before the SG heat transfer capability is reduced, the primary system variables never approach a DNB condition. This event is classified as an ANS Condition II event.

The loss of normal feedwater flow transient considers two cases with four loops operating initially. The first is the case where offsite AC power is maintained. The second is the case where offsite AC power is lost. As stated in FSAR Section 15.2.7.2, a detailed analysis using the LOFTRAN code (WCAP-7907-P-A) is performed in order to obtain the plant transients following a loss of normal feedwater. The code computes pertinent variables including the steam generator level, pressurizer water level, and reactor coolant average temperature.

FSAR Section 15.2.7.3 concludes that the results of the analysis show that a loss of normal feedwater does not adversely affect the core, the RCS or the steam system since the auxiliary feedwater capacity is such that RC water is not relieved from the pressurizer relief or safety valves, and the water level in all SG receiving AFW is maintained above the tube sheets.

Westinghouse NSALs 02-3 Rev. 01; 02-4, Rev. 0; and 02-5 Rev 01 identified potential non-conservative errors in SG level measurement due to the pressure drop across the SG mid deck plate; potential impacts on the SG level reactor trip setpoints; and potential impacts to SG water level control system uncertainties utilized as initial condition assumptions for SG water level related safety analyses. DNC implemented modifications to the MPS3 narrow range SG level measurement instrument loops during 3R11 (April, 2007) to address changes in instrument uncertainties for level control and setpoints used for SG low-low level reactor trip.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.2.3.2 Technical Evaluation

2.8.5.2.3.2.1 Introduction

A loss of normal feedwater (LONF) flow (FSAR 15.2.7) (from pump failures, valve malfunctions, or a complete loss of offsite AC power) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If an alternative supply of feedwater is not supplied, core residual heat following reactor trip would heat the primary system water to the point where water relief from the pressurizer could occur, resulting in a substantial loss of water from the RCS. Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables do not approach a condition that causes a DNBR limit violation.

Two scenarios are analyzed for a LONF event. The first is the case where offsite AC power is maintained, and the second is the case where offsite AC power is lost which results in reactor coolant pump coastdown as discussed in Licensing Report Section 2.8.5.2.2.

The following events occur following the reactor trip for the LONF:

- The main steam pressure relieving valves are automatically opened to the atmosphere as the main steam system pressure rises following a loss of feedwater. The condenser is assumed unavailable for steam dump. If the relief capacity of the main steam pressure relieving valves is inadequate, the main steam safety valves (MSSVs) can lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.
- Plant vital instruments are supplied from emergency DC power sources for the case with a loss of offsite power.

The following provide the necessary protection in the event of a LONF:

- The reactor can be tripped on one or more of the following reactor trip signals:
  - Pressurizer high pressure trip signal
  - Overtemperaure T trip signal
  - Low-low steam generator water level trip signal in any steam generator
- Two MDAFW pumps are started on any of the following:
  - Low-low water level in two-out-of-four level signals in any steam generator
  - Loss of offsite power
  - Safety injection signal
  - Manual actuation
  - AMSAC actuation signal
- One TDAFW pump is started on any of the following:
  - Low-low water level in two-out-of-four level signals in any two of four steam generators
  - Manual actuation
  - AMSAC actuation signal
- The MSSVs open to provide an additional heat sink and protection against secondary side overpressure.
- The pressurizer safety valves (PSVs) may open to provide protection against overpressure of the RCS.

The analysis showed that following a LONF (with or without offsite power), the AFW system is capable of removing the stored and residual heat, thus preventing overpressurization of the RCS, overpressurization of the secondary side, water relief from the pressurizer, and uncovery of the reactor core.

2.8.5.2.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The following assumptions were made in the LONF analyses:

- The plant is initially operating at 102 percent of the NSSS power of 3666 MWt.
- For the case with offsite power, a maximum RCP heat of 20.0 MWt was conservatively modeled. The RCPs were assumed to continuously operate throughout the transient providing a constant reactor coolant volumetric flow equal to the thermal design flow value. Although not assumed in this case, the RCPs could be manually tripped at some later time in the transient to reduce the heat addition to the RCS caused by the operation of the pumps.
- For the case without offsite power, power was assumed to be lost to the RCPs after the start of rod motion. For this case, the nominal RCP heat of 16.0 MWt was modeled. Assuming a nominal RCP heat was conservative since the RCPs coasted down and ceased to add heat to the primary coolant while the core decay heat was based on a slightly higher initial core power. The post-trip heat removal from the core relied upon natural circulation flow in the RCS loops.
- Main feedwater temperature conditions at 390°F and 445.3°F were analyzed.
- Reactor vessel average coolant temperature (T_{avg}) conditions at the low and high ends of the full power temperature window (571.5°F to 589.5°F) were considered. In addition, since the pressurizer level program has a breakpoint at 587°F (i.e., pressurizer level program is linear from 28 percent span at the no-load temperature of 557°F to 64 percent span at a full power temperature of 587°F) that point was also specifically analyzed.
- The direction of conservatism for both initial reactor vessel average coolant temperature and pressurizer pressure can vary. As such, cases were considered with the initial temperature and pressure uncertainties applied in each direction. The initial average temperature uncertainty was assumed to be +5.0/-4.0°F. The initial pressurizer pressure uncertainty was assumed to be $\pm$ 50 psi.
- Reactor trip occurs on steam generator low-low water level at 0 percent of the narrow range span.
- It was assumed that two MDAFW pumps are available to supply flow to all four steam generators, 60 seconds following a low-low steam generator water level signal. The worst single failure for this analysis is the loss of the TDAFW pump. Minimum AFW flow from the two MDAFW pumps is modeled as a function of steam generator pressure.
- The pressurizer heaters were modeled to exacerbate the heatup and volumetric expansion of the water in the pressurizer. In addition, the pressurizer sprays were assumed to be operable, and cases were analyzed with and without the pressurizer power-operated relief valves (PORV)s available to determine the limiting configuration. It was found that the cases without PORV availability were more limiting.

- Secondary system steam relief is achieved through the self-actuated MSSVs. Note that steam relief is provided by the power-operated relief valves or condenser dump valves for most cases of LONF. However, the condenser dump valves and the power-operated relief valves were assumed to be unavailable.
- The MSSVs were modeled assuming a 3 percent tolerance and an accumulation model that assumes that the valves were wide open once the pressure exceeded the setpoint (plus tolerance) by 5 psi (accumulation).
- Core residual heat generation was based on the 1979 version of ANS 5.1 (Reference 1). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates. Long-term operation at the initial power level preceding the trip was assumed.
- Steam generator tube plugging (SGTP) levels of both 0 and 10 percent were analyzed.

Based on its frequency of occurrence, the LONF accident is considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit.
- Pressures in the RCS and MSS are maintained below 110 percent of the design pressures.
- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently.

With respect to overpressurization, the LONF event, both with and without offsite power, is bounded by the loss of load/turbine trip event discussed in Section 2.8.5.2.1. With respect to DNB, the LONF event with offsite power is also bounded by the loss of load/turbine trip event, and the LONF event without offsite power is bounded by the loss-of-flow event discussed in Section 2.8.5.3.1.

A restrictive acceptance criterion; that the pressurizer does not become water solid was used for this event. This criterion established the acceptable capacity of the AFW system, ensuring that the pressure criteria and minimum DNBR criterion remained satisfied for the long-term portion of the event, and demonstrated that a more serious plant condition was precluded.

2.8.5.2.3.2.3 Description of Analyses and Evaluations

A detailed analysis using the RETRAN (Reference 2) computer code was performed to determine the plant transient conditions following a LONF. The code modeled the core neutron kinetics, RCS, pressurizer, pressurizer heaters, pressurizer sprays, steam generators, MSSVs, and the AFW system. The code also computed pertinent variables, including the pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

This computer code is different than that used for the current licensing basis analysis where the LOFTRAN code is used. RETRAN has been approved by the NRC for the analysis of loss of normal feedwater flow transients (Reference 2).

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the loss of normal feedwater flow analysis. As stated in Section 2.8.5.2.3.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.2.3.2.4 Results

LONF Flow Results with Offsite Power

The most limiting LONF case with offsite power available was with the temperature uncertainty subtracted from the nominal T_{avg} value at the pressurizer level program breakpoint (i.e., 587°F - 4°F), pressure uncertainty added to the nominal value (i.e., 2250 psia + 50 psi), PORVs not available, 10 percent SG tube plugging, and high (445.3°F) main feedwater temperature conditions.

The calculated sequence of events for this event is listed in Table 2.8.5.2.3-1. Figures 2.8.5.2.3-1 through 2.8.5.2.3-5 present transient plots of the significant plant parameters following a LONF with offsite power, with the assumptions listed in Section 2.8.5.2.3.2.2.

Numerical results of the SPU analysis along with a comparison to the previous analysis results are shown in Table 2.8.5.2.3-2. As expected, the SPU results are more limiting.

Following the reactor and turbine trip from full load, the water level in the steam generators fell due to reduction of the steam generator void fraction and because steam flow through the safety valves continued to dissipate the stored and generated heat. One minute following the initiation of the low-low level trip, the MDAFW pumps automatically started, consequently reducing the rate at which the steam generator water level was decreasing.

The capacity of the MDAFW pumps enabled sufficient heat transfer from each steam generator to dissipate the core residual heat without the pressurizer reaching a water solid condition (as shown in Figure 2.8.5.2.3-3). This precluded any water relief through the RCS pressurizer relief valves or PSVs.

LONF Flow Results without Offsite Power

The most limiting LONF case without offsite power available was with the temperature uncertainty subtracted from the lowest nominal T_{avg} value (i.e., 571.5°F - 4°F), pressure uncertainty added to the nominal value (i.e., 2250 psia + 50 psi), PORVs not available, 0 percent SG tube plugging, and low (390.0°F) main feedwater temperature conditions.

The calculated sequence of events for this event is listed in Table 2.8.5.2.3-3. Figures 2.8.5.2.3-6 through 2.8.5.2.3-10 present transient plots of the significant plant parameters following a LONF without offsite power, with the assumptions listed in Section 2.8.5.2.3.2.2 of this Licensing Report.

Numerical results of the SPU analysis along with a comparison to the previous analysis results are shown in Table 2.8.5.2.3-4. As expected, the SPU results are more limiting.

Following the reactor and turbine trip from full load, the water level in the steam generators fell due to reduction of the steam generator void fraction and because steam flow through the safety valves continued to dissipate the stored and generated heat. One minute following the initiation of the low-low level trip, the MDAFW pumps automatically started, consequently reducing the rate at which the steam generator water level was decreasing.

The capacity of the MDAFW pumps enabled sufficient heat transfer from each steam generator to dissipate the core residual heat without the pressurizer reaching a water solid condition (as shown in Figure 2.8.5.2.3-8). This precluded any water relief through the RCS pressurizer relief valves or PSVs.

With respect to DNB, the LONF event with offsite power available is bounded by the loss of load event (see Section 2.8.5.2.1), and without offsite power is bounded by the loss of flow event (see Section 2.8.5.3.1) demonstrating that the minimum DNBR was greater than the safety analysis limit value. With respect to overpressurization, the LONF event is bounded by the loss of load event (see Section 2.8.5.2.1) demonstrating that the peak primary and secondary system pressures remained below 110 percent of their respective design pressures at all times. In addition, the results of the analysis showed that the pressurizer did not reach a water solid condition. Therefore, the LONF event did not adversely affect the core, the RCS, or the MSS.

2.8.5.2.3.3 Conclusion

DNC has reviewed the analyses of the loss of normal feedwater flow event and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of the loss of normal feedwater flow. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -10, -15, and -26 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the loss of normal feedwater flow event

2.8.5.2.3.4 References

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

2. WCAP-14882-P-A (Proprietary), WCAP-15234-A (Nonproprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses), Huegel, D.S., et al., April 1999 and May 1999, respectively.

Table 2.8.5.2.3-1
Time Sequence of Events – LONF with Offsite Power

Event	Time (sec)
Main Feedwater Flow Stops	0.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	34.0
Rods Begin to Drop	36.0
Flow from Two MDAFW Pumps is Initiated	94.0
Long-Term Peak Water Level in Pressurizer Occurs	2210.0
Core decay and RCP Heat Decreases to AFW Heat Removal Capacity	~2280

Table 2.8.5.2.3-2
Loss of Normal Feedwater with Offsite Power Results and Comparison to Previous Results

	SPU Analysis	Previous Analysis	Limit
Peak Pressurizer Water Volume (ft^3)	1731	1061	1800

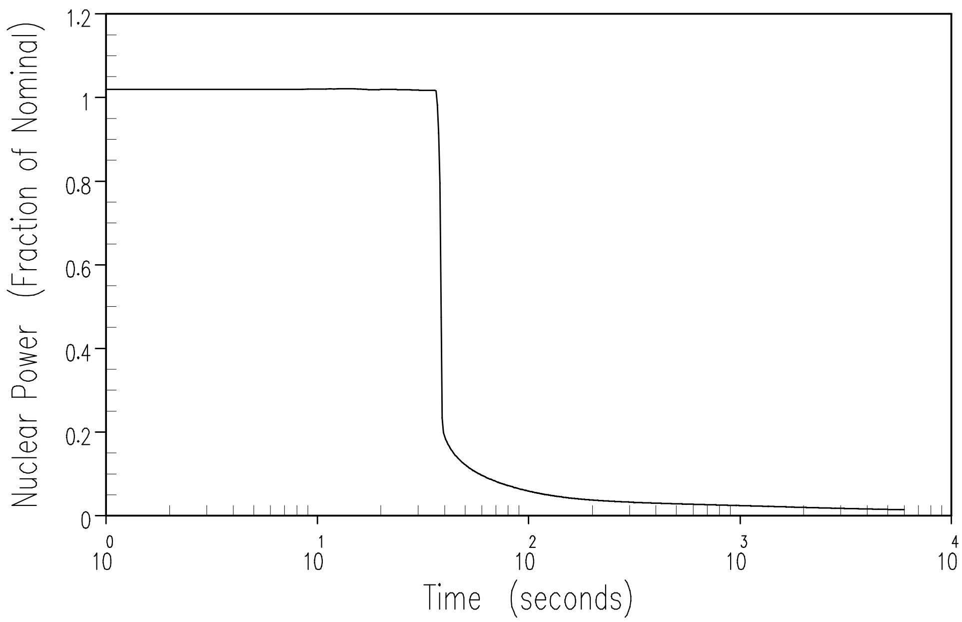
Table 2.8.5.2.3-3
Time Sequence of Events – LONF without Offsite Power

Event	Time (sec)
Main Feedwater Flow Stops	0.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	39.5
Rods Begin to Drop	41.5
Reactor Coolant Pumps Tripped	43.5
Flow from Two MDAFW Pumps is Initiated	99.5
Long-Term Peak Water Level in Pressurizer Occurs	2922.0
Core decay and RCP Heat Decreases to AFW Heat Removal Capacity	~2980

Table 2.8.5.2.3-4
Loss of Normal Feedwater without Offsite Power Results and Comparison to Previous Results

	SPU Analysis	Previous Analysis	Limit
Peak Pressurizer Water Volume (ft^3)	1724	1493	1800

Figure 2.8.5.2.3-1
LONF with Offsite Power Nuclear Power and Core Average Heat Flux vs. Time



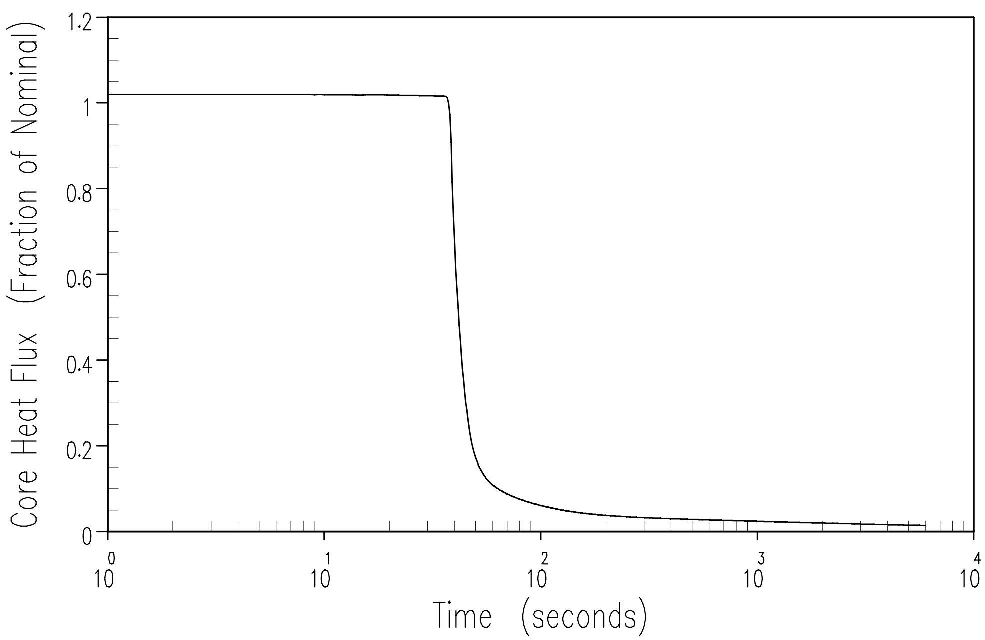


Figure 2.8.5.2.3-2
LONF with Offsite Power Reactor Coolant Flow Rate and Loop Temperature vs. Time

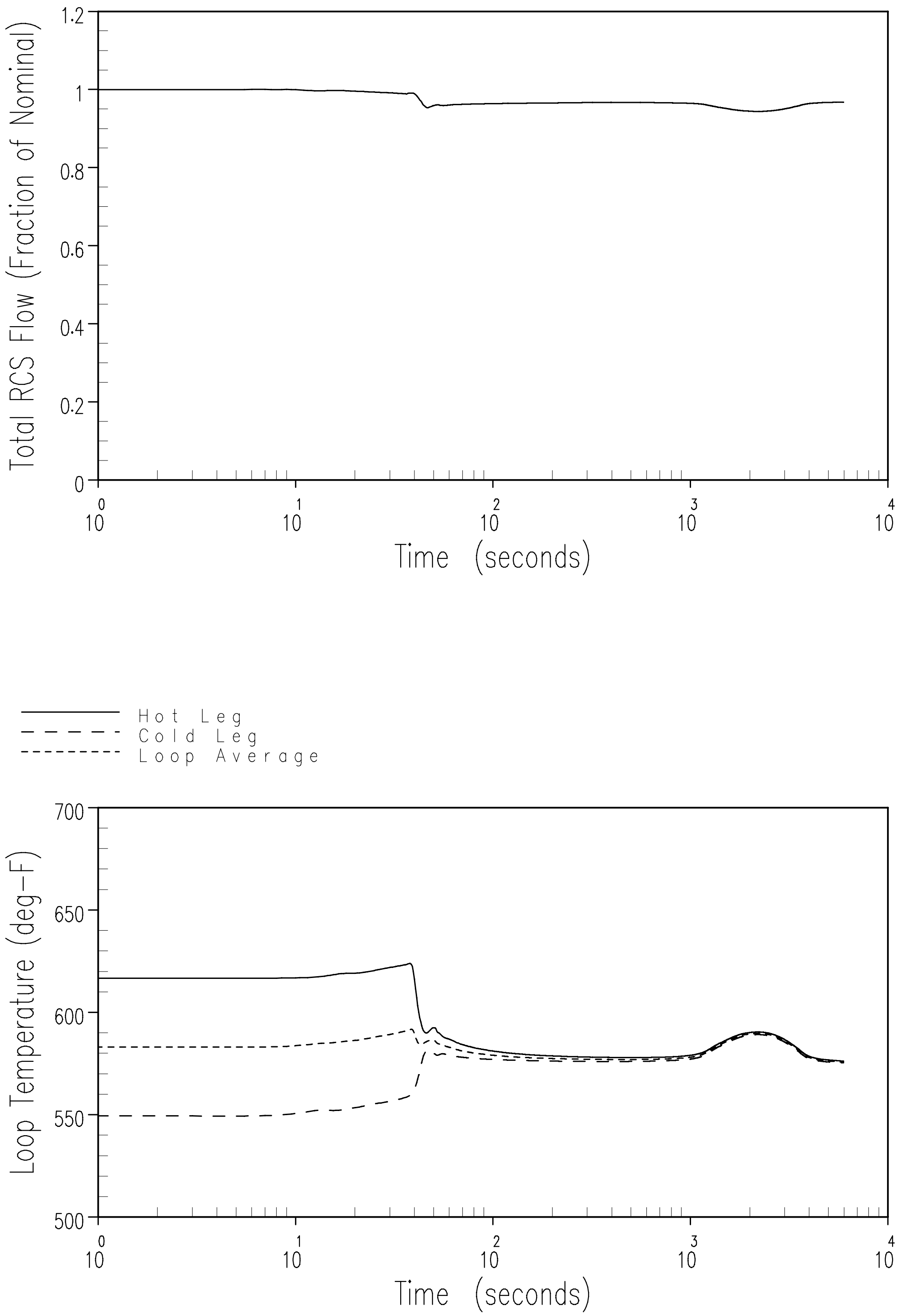
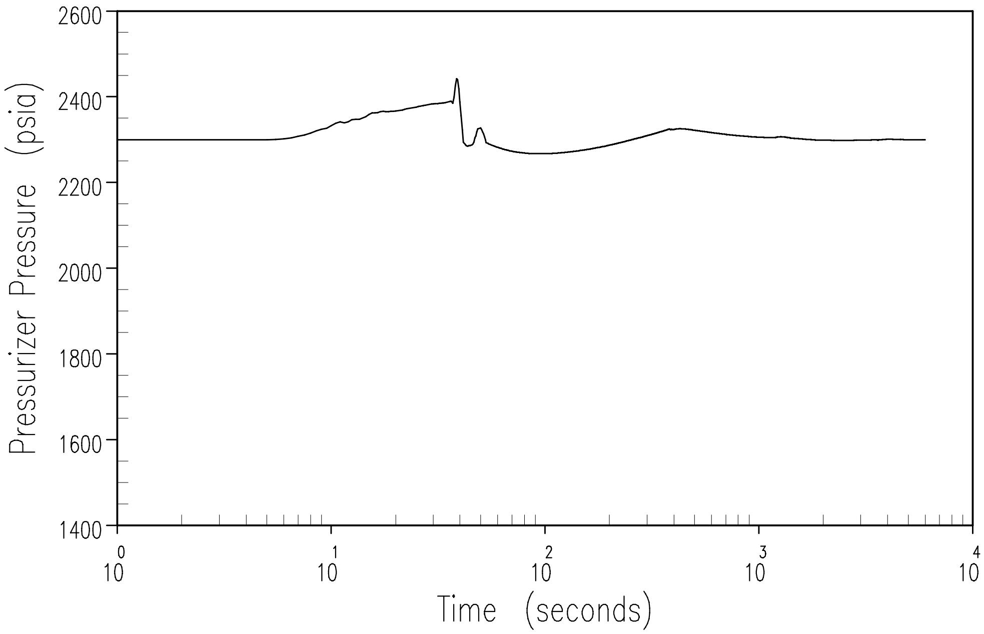


Figure 2.8.5.2.3-3
LONF with Offsite Power Pressurizer Pressure and Water Volume vs. Time



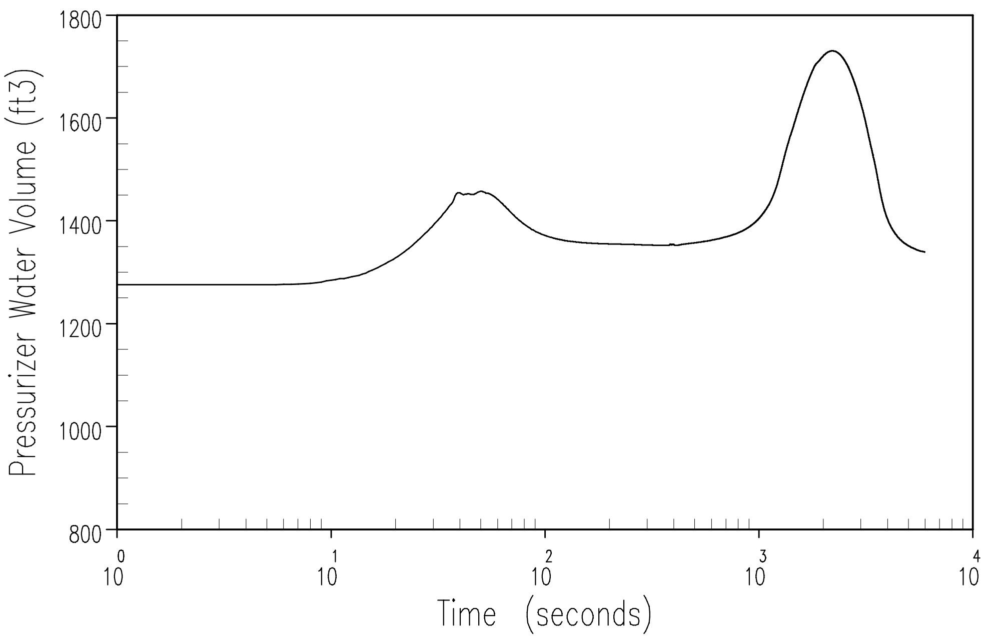
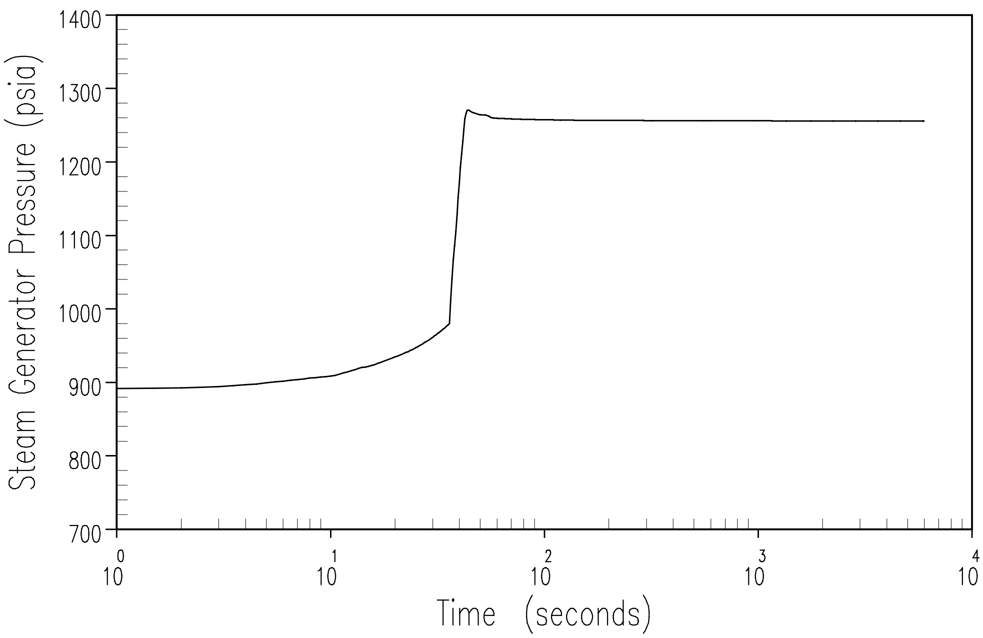


Figure 2.8.5.2.3-4
LONF with Offsite Power Steam Generator Pressure and Mass vs. Time



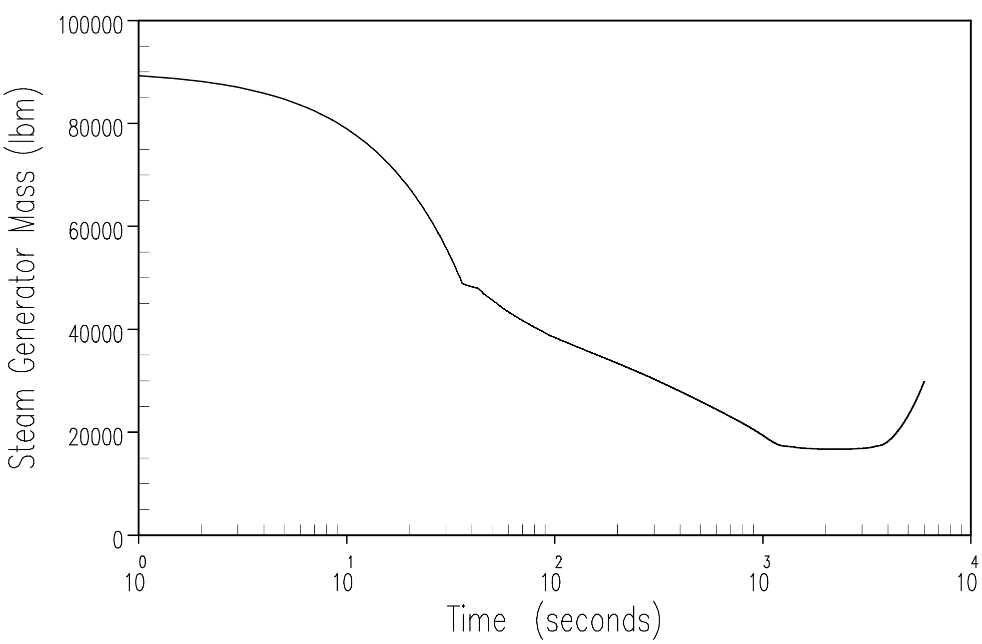


Figure 2.8.5.2.3-5
LONF with Offsite Power Auxiliary Feedwater Flow vs. Time

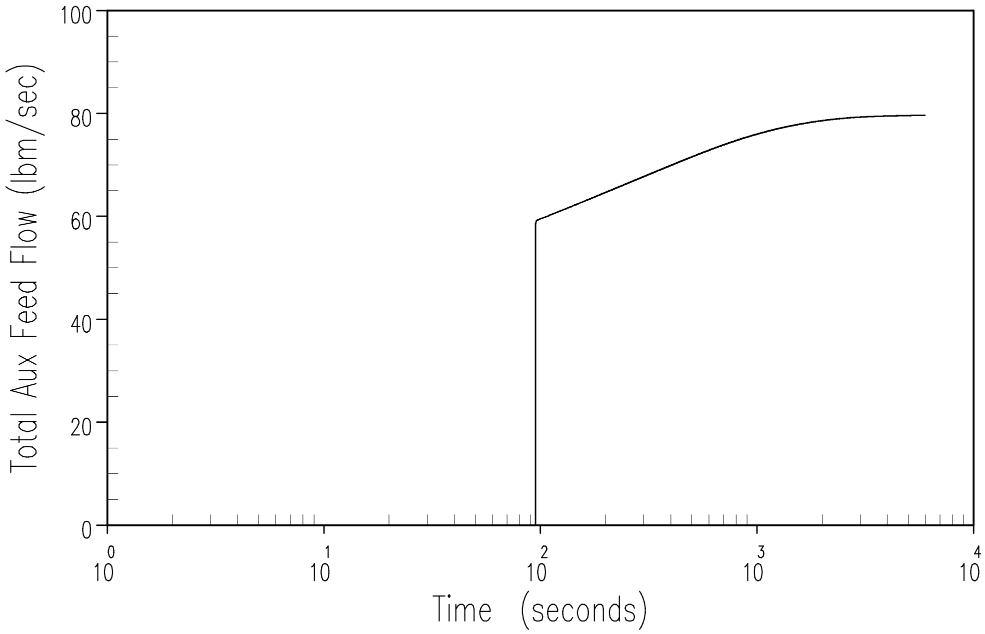


Figure 2.8.5.2.3-6
LONF without Offsite Power Nuclear Power and Core Average Heat Flux vs. Time

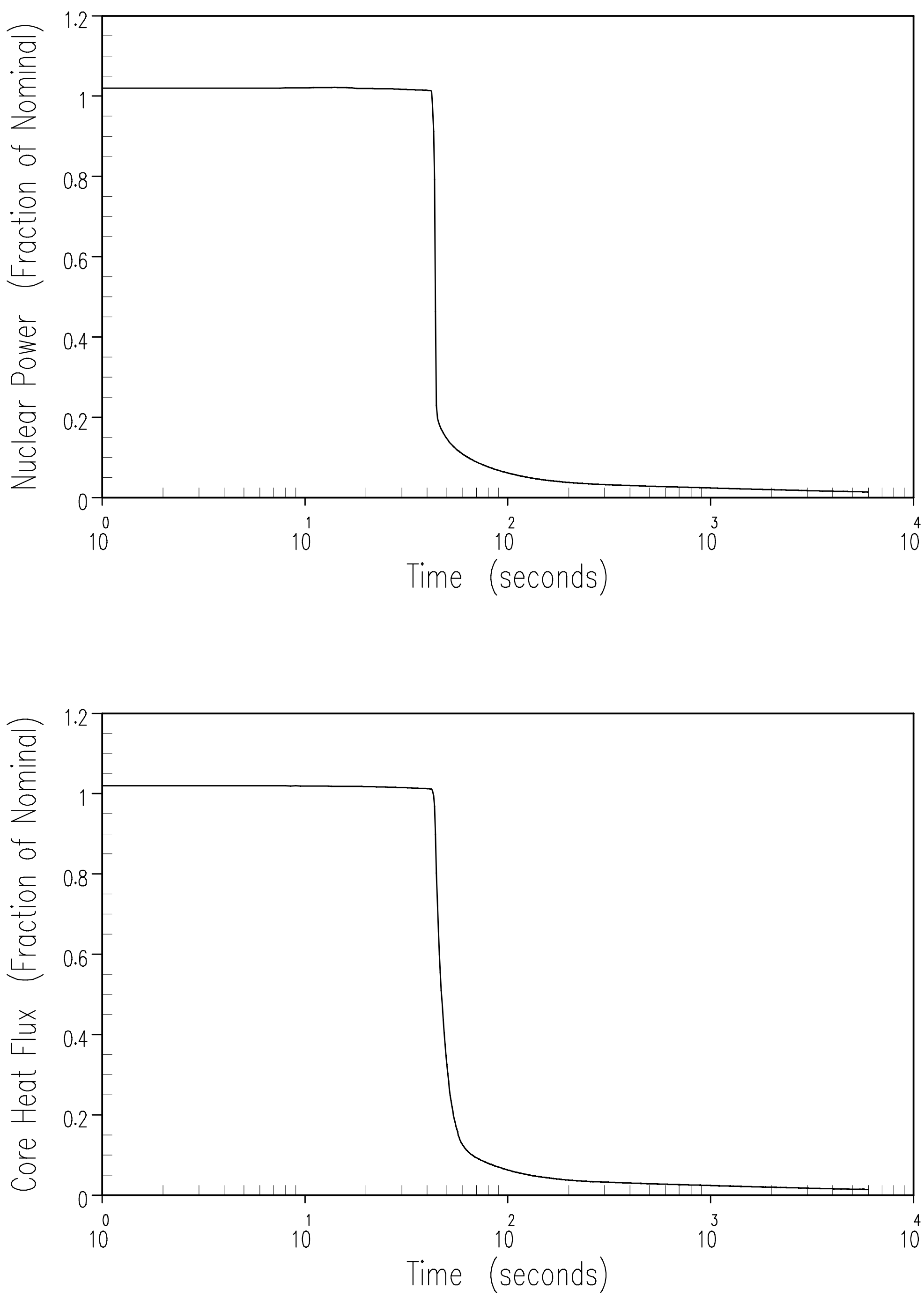
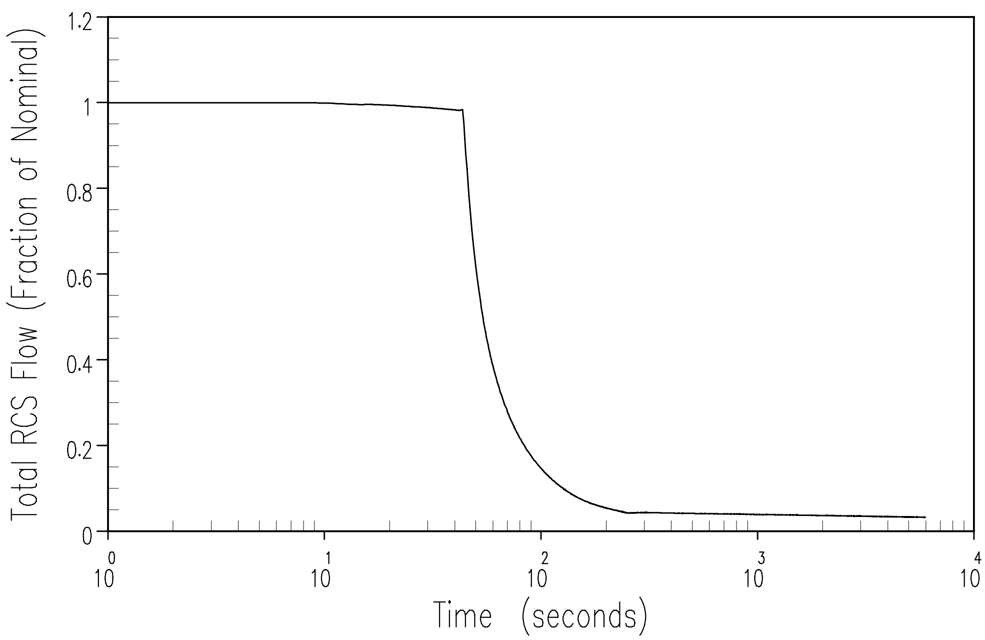


Figure 2.8.5.2.3-7
LONF without Offsite Power Reactor Coolant Flow Rate and Loop Temperature vs. Time



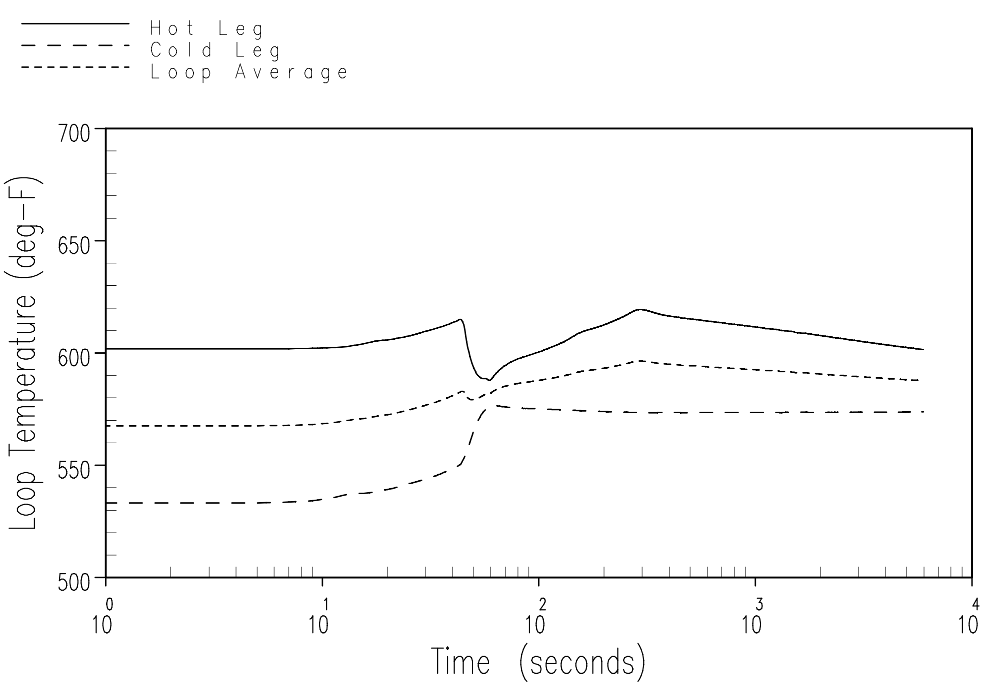


Figure 2.8.5.2.3-8
LONF without Offsite Power Pressurizer Pressure and Water Volume vs. Time

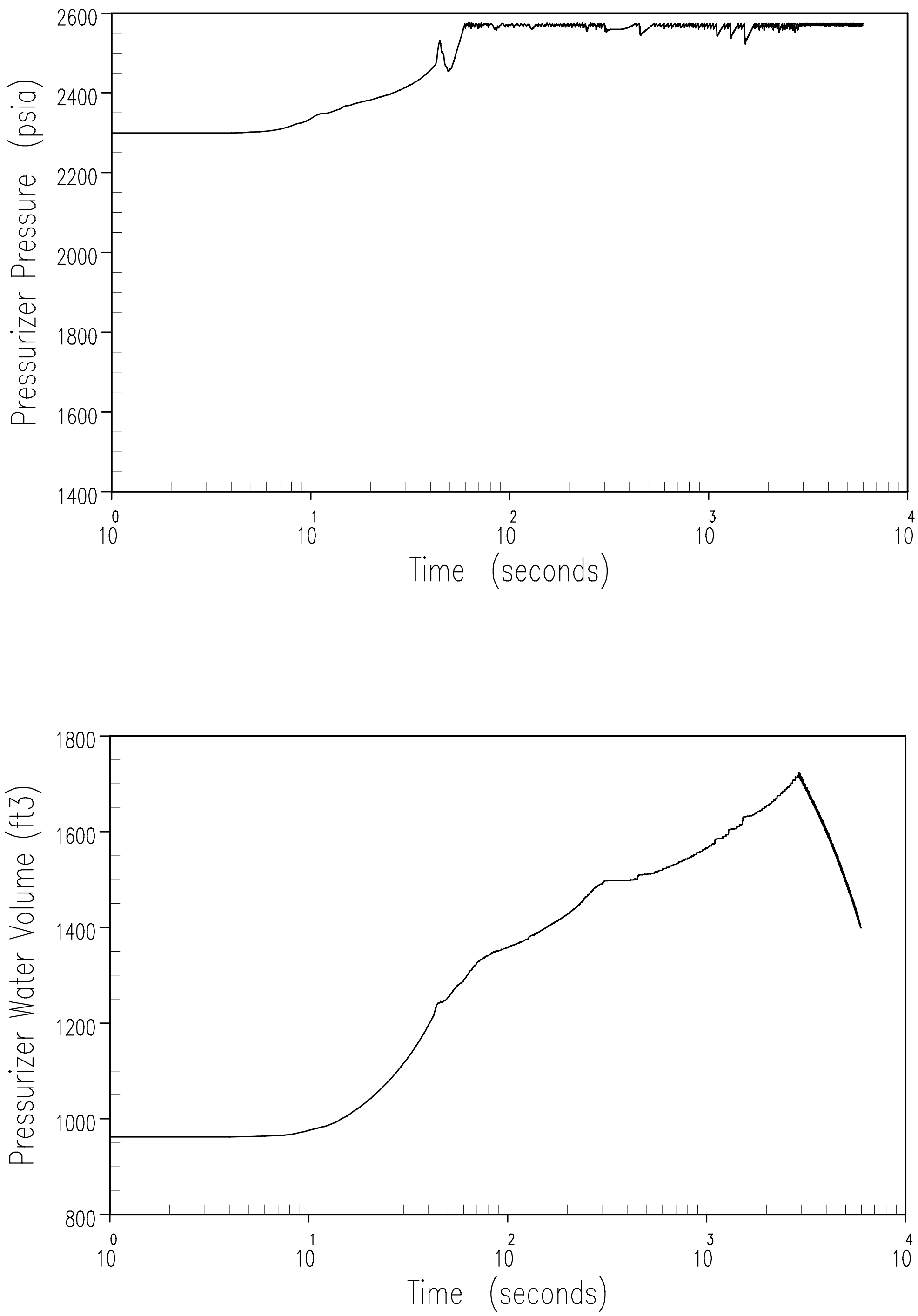
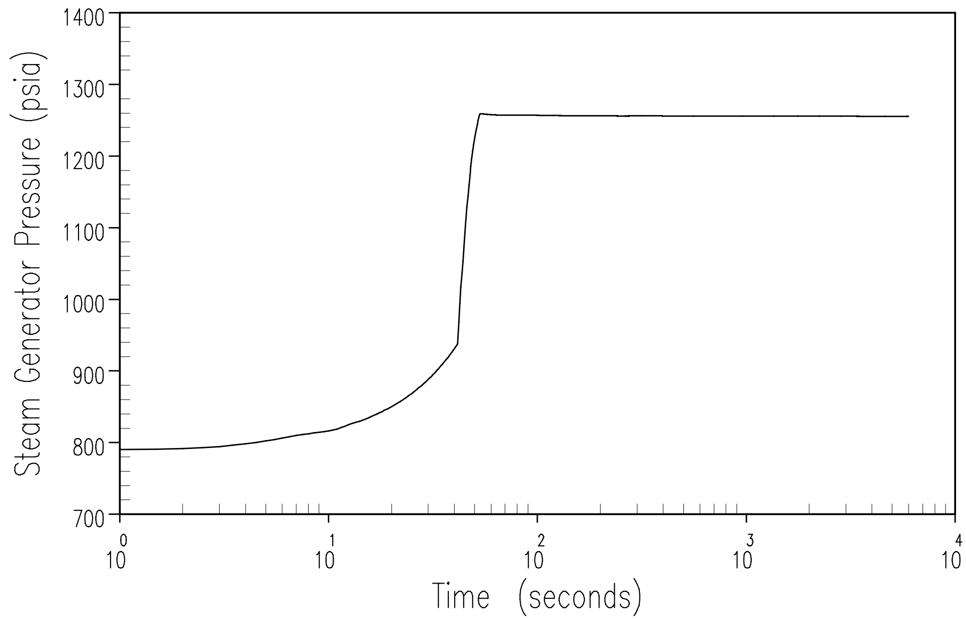


Figure 2.8.5.2.3-9
LONF without Offsite Power Steam Generator Pressure and Mass vs. Time



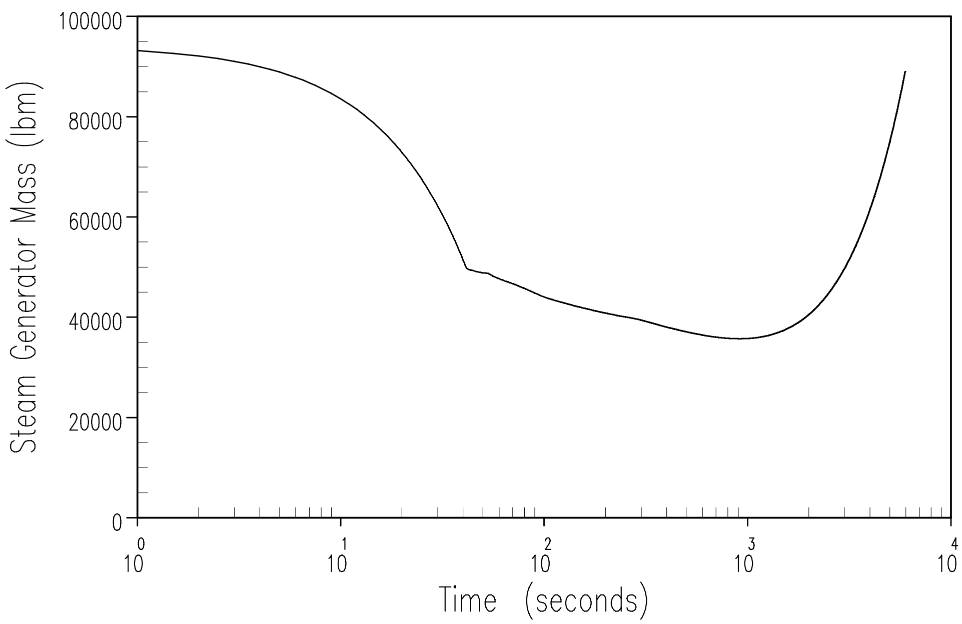
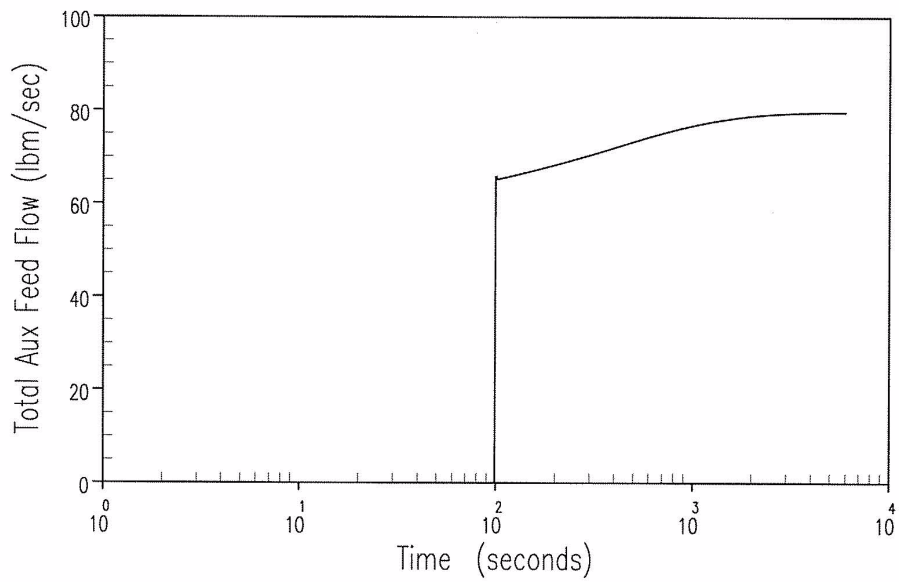


Figure 2.8.5.2.3-10
LONF without Offsite Power Auxiliary Feedwater Flow vs. Time



2.8.5.2.4 Feedwater System Pipe Breaks Inside and Outside Containment

2.8.5.2.4.1 Regulatory Evaluation

Depending upon the size and location of the break and the plant operating conditions at the time of the break, the break could cause either a RCS cooldown (by excessive energy discharge through the break) or a RCS heatup (by reducing feedwater flow to the affected SG). In either case, reactor protection and safety systems are actuated to mitigate the transient.

The DNC review covered:

- The postulated initial core and reactor conditions
- The methods of thermal and hydraulic analyses
- The sequence of events
- The assumed response of the reactor coolant and auxiliary systems
- The functional and operational characteristics of the reactor protection system
- The operator actions
- The results of the transient analyses

The acceptance criteria are based on:

- GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to ensure the capability to cool the core is maintained
- GDC-28, insofar as it requires that the reactivity control systems be designed to ensure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core
- GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized
- GDC-35, insofar as it requires that the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling.

Specific review criteria are contained in SRP Section 15.2.8, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), Section 15.2.8, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to:

- GDC-27, Combined Reactivity Control Systems Capability, is described in FSAR Section 3.1.2.27.

  MPS3 is provided with a means of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. FSAR Chapters 4 and 9 discuss these means in detail. Combined use of the rod cluster control system and the chemical shim control system permit the necessary shutdown margin to be maintained during long term xenon decay and plant cooldown. The single highest worth control cluster is assumed to be stuck full-out upon trip for this determination. FSAR Chapter 15 describes accident assumptions in detail.

- GDC-28, Reactivity Limits, is described in FSAR Section 3.1.2.28.

  The maximum reactivity worth of control rods and the maximum rate of reactivity insertion employing control rods are limited to values that prevent rupture of the reactor coolant system boundary or disruptions of the core or vessel internals to a degree that could impair the effectiveness of emergency core cooling.

  The maximum positive reactivity insertion rates for the withdrawal of RCCAs and the dilution of the boric acid in the RCS are limited by the physical design characteristics of the RCCAs and of the CVCS. The Technical Specifications on shutdown margin and on RCCA insertion limits and bank overlaps as functions of power provide additional assurance that the consequences of the postulated accidents are no more severe than those presented in the analyses of FSAR Chapter 15. Reactivity insertion rates, dilution, and withdrawal limits are also discussed in FSAR Section 4.3. The capability of the CVCS to avoid an inadvertent excessive rate of boron dilution is discussed in FSAR Chapter 15.

  Assurance of core cooling capability following Condition IV accidents, such as rod ejections, steam line breaks, etc., is given by keeping the reactor coolant pressure boundary stresses within faulted condition limits as specified by applicable ASME codes. Structural deformations are checked also and limited to values that do not jeopardize the operation of necessary safety features.

- GDC-31, Fracture Prevention of Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.31.

  Close control is maintained over material selection and fabrication for the RCS to assure that the boundary behaves in a non-brittle manner. The RCS materials exposed to the coolant are corrosion resistant stainless steel or Inconel. The NIL ductility reference temperature of the RV structural steel is established by Charpy V-notch and drop weight tests, in accordance with 10 CFR 50, Appendix G.

As part of the RV specification, certain requirements which are not specified by the applicable ASME Codes are performed as follows:

1. Ultrasonic Testing - In addition to code requirements, a 100 percent volumetric ultrasonic test of RV plate for shear wave and a post-hydro test ultrasonic map of all full penetration ferritic pressure boundary welds in the pressure vessel are performed. Cladding bond ultrasonic inspections to more restrictive requirements than those specified in the code are also required to preclude interpretation problems during inservice inspection.

2. Radiation Surveillance Program – In the surveillance programs, the evaluation of the radiation damage is based on pre-irradiation and post-irradiation testing of Charpy V-notch and tensile specimens. These programs are directed toward evaluation of the effect of radiation on the fracture toughness of RV steels based on the reference transition temperature approach, and the fracture mechanics approach, and are in accordance with ASTM-E-185-73, "Recommended Practices for Surveillance Tests for Nuclear Reactor Vessels," and the requirements of 10 CFR 50, Appendix H.

3. RV core region material chemistry (copper, phosphorous, and vanadium) is controlled to reduce sensitivity to embrittlement due to radiation over the life of the plant.

The fabrication and quality control techniques used in the fabrication of the RCS are consistent with those used for the RV. The inspections of the RV, pressurizer, piping, pumps and S/Gs are governed by ASME Code requirements (Refer to FSAR Chapter 5).

Allowable pressure-temperature relationships for plant heatup and cooldown rates are calculated using methods derived from the ASME Code, Section III, Appendix G, Protection Against Non-Ductile Failure. This approach specifies that allowed stress intensity factors for all vessel operating conditions may not exceed the referenced stress intensity factor (KIR) for the metal temperature at any time. Operating specifications include conservative margins for predicted changes in the material reference temperature due to irradiation.

- GDC-35, Emergency Core Cooling, is addressed in FSAR Section 3.1.2.35.

An ECCS is provided to cope with any LOCA in the plant design basis. Abundant cooling water is available in an emergency to transfer heat from the core at a rate such that the clad metal - water reaction is limited to less than one percent. Adequate design provisions are made to assure performance of the required safety functions even with a single failure.

FSAR Section 6.3 includes details of the capability of the systems. FSAR Chapter 15 includes an evaluation of the adequacy of the system functions. Performance evaluations are conducted in accordance with 10 CFR 50.46 and 10 CFR 50, Appendix K.

FSAR Section 15.2.8.1 states that a major feedwater line rupture is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell side fluid inventory in the steam generators. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. (A break upstream of the feedline check valve would affect the nuclear steam supply system only as a loss of feedwater. This case is covered by the evaluation in FSAR Section 15.2.7). A major feedwater line rupture is classified as an ANS Condition IV event.

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a RCS cooldown (by excessive energy discharge through the break) or a RCS heatup. Potential RCS cooldown resulting from a secondary pipe rupture is evaluated in FSAR Section 15.1.5. Therefore, only the RCS heatup effects are evaluated for a feedwater line rupture.

The transient is analyzed utilizing the LOFTRAN Code (WCAP-7907-P-A). It computes pertinent variables including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

FSAR Section 15.2.8.3 concludes that the results of the analyses show that for the postulated feedwater line rupture, the assumed auxiliary feedwater system capacity is adequate to remove decay heat, to prevent over-pressurizing the RCS, and to prevent uncovering the reactor core. Radioactivity doses from the postulated feedwater line rupture are less than those previously presented for the postulated steam line break. All applicable acceptance criteria are therefore met.

Westinghouse NSALs 02-3 Rev. 01; 02-4, Rev. 0; and 02-5 Rev 01 identified potential non-conservative errors in SG level measurement due to the pressure drop across the SG mid deck plate; potential impacts on the SG level reactor trip setpoints; and potential impacts to SG water level control system uncertainties utilized as initial condition assumptions for SG water level related safety analyses. DNC implemented modifications to the MPS3 narrow range SG level measurement instrument loops during 3R11 (April, 2007) to address changes in instrument uncertainties for level control and setpoints used for SG low-low level reactor trip.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.2.4.2 Technical Evaluation

The specific acceptance criterion applied for this event is that there is no boiling in the hot legs prior to the point in the transient where the heat removal capacity of the auxiliary feedwater (AFW) system exceeds the heat generation. This conservatively ensures that the core remains covered and geometrically intact for the duration of the event. Furthermore, the analysis ensures that appropriate margin for malfunctions, such as stuck rods, were accounted for in the safety analysis assumptions. This conservatively satisfies the MPS3 current licensing basis with respect to the requirements of GDC-27, GDC-28, GDC-31 and GDC-35.

The discussion below demonstrates that all applicable acceptance criteria are met for this event at MPS3 at SPU conditions.

2.8.5.2.4.2.1 Introduction

A major feedwater line break (FSAR Section 15.2.8) is defined as a break in a feedwater pipe large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator can also be discharged through the break. Furthermore, a break in this location could preclude the subsequent addition of AFW to the affected steam generator. A break upstream of the feedline check valve would affect the nuclear steam supply system (NSSS) only as a loss of feedwater. This case is covered by the loss of normal feedwater (LONF) analysis presented in Section 2.8.5.2.3.

Depending upon the size of the break and the plant operating conditions at the time of the rupture, the break could either cause an RCS heatup or cooldown. The potential RCS cooldown resulting from a secondary pipe break is evaluated in the steamline break analysis presented in Section 2.8.5.1.2.2.1. Only the RCS heatup effects of a feedline break are presented in this section.

A feedline break reduces the ability to remove heat generated by the core from the RCS. The AFW system is provided to ensure that adequate feedwater is available to provide decay heat removal.

2.8.5.2.4.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The following key assumptions were made in the analysis:

- SPU NSSS power up to 3666 MWt plus 2 percent power uncertainty was assumed.
- The initial RCS average temperature was set to 594.5°F; the nominal high T_{avg} value of 589.5°F, plus a T_{avg} uncertainty of 5.0°F.
- The initial RCS pressure was 50 psid above its nominal value of 2250 psia to account for initial condition uncertainties.
- The initial pressurizer level was set to the nominal full power programmed value of 64 percent span plus 7.6 percent span to account for initial condition uncertainties.
- The initial steam generator water level was set to the nominal value (50 percent narrow range span) plus 12 percent narrow range span in the faulted steam generator and the nominal value minus 12 percent NRS in the intact steam generator to account for initial condition uncertainties.
- The main feedwater flow to all steam generators was assumed to be lost at the time the break occurred (all main feedwater spilled out through the break).
- The full double-ended main feedwater pipe break was assumed. A break size of 0.890 ft^2 was analyzed for MPS3.
- The single failure assumption was conservatively set as the loss of the highest capacity (i.e. turbine driven) AFW pump. As such, flow from only the motor driven AFW pumps, as a function of steam generator pressure, is credited. No AFW flow is assumed to reach the faulted steam generator.
- Since the MPS3 ECCS can inject into the RCS at pressures greater than the pressurizer power-operated relief valve (PORV) opening pressure, the PORVs were assumed to be unavailable.

- Reactor trip was assumed to be actuated when the steam generator low-low level trip setpoint was reached in the ruptured steam generator. A conservative setpoint of 0 percent narrow range span was modeled. A description of the method used by RETRAN to calculate steam generator level is provided in Section 3.8.2 of WCAP-14882-P-A (Reference 2).
- The main steamline isolation valves serve to isolate the intact steam generators from the faulted steam generator.
- Credit was taken for heat energy deposited in portions of the RCS metal during the RCS heatup, as described in the approved methods presented in Reference 3.
- No credit was taken for charging or letdown.
- Maximum steam generator tube plugging of 10 percent was assumed to minimize primary-to-secondary side heat transfer.
- Steam generator heat transfer across the tubes was adjusted as the shell-side liquid inventory decreased. Specifically, the heat transfer correlation for the steam generator tubes (heat conductors) is automatically adjusted by the RETRAN code for the changing conditions as the tubes uncover.
- The feedline break discharge quality during the transient is calculated by the RETRAN code as a function of temperature and pressure with respect to time. The break flow prior to reactor trip consists of only saturated water (0 percent quality), with increasing steam quality following reactor trip; once the feedring uncovers, break quality is underpredicted (i.e, entrainment of the break flow is overpredicted). This maximizes the mass discharge out of the break, thereby minimizing the heat transfer capability of the faulted steam generator and maximizing the overall RCS heatup.
- Conservative core decay heat was assumed based upon long-term operation at the initial power level preceding the trip (ANS-5.1-1979 plus 2 uncertainty).
- No credit was taken for the following potential protection logic signals to mitigate the consequences of the accident:
  - High-pressurizer pressure
  - High-pressurizer level
  - High-containment pressure
  - Overtemperature T

The feedline break accident is an ANS Condition IV occurrence. Condition IV events are faults that are not expected to occur, but are postulated because their consequences would include the potential for release of significant amounts of radioactive material.

The specific criteria used in evaluating the consequences of the feedline break were:

- Pressures in the RCS and MSS are maintained below 110 percent of the design pressures for low probability events and below 120 percent of the design pressures for very low probability events such as double-ended guillotine breaks.

- Any fuel damage that can occur during the transient is of a sufficiently limited extent that the core will remain in place and geometrically intact with no loss of core cooling capability.
- Any activity release is such that the calculated doses at the site boundary are within 10 CFR 50.67 (Reference 1).

To conservatively meet these basic criteria, the internal criterion established is that no bulk boiling occurs in the primary coolant system following a feedline break prior to the time that the heat removal capability of the steam generators, being fed AFW, exceeds NSSS residual heat generation.

2.8.5.2.4.2.3 Description of Analyses and Evaluations

The transient response following a feedline break event was calculated by a detailed digital simulation of the plant. The analysis modeled a simultaneous loss of main feedwater to all steam generators and subsequent reverse blowdown of the faulted steam generator. The analysis was performed using the RETRAN code (Reference 2), which simulates the neutron kinetics, RCS, pressurizer, pressurizer relief valves and PSV, pressurizer spray, steam generators, and steam generator safety valves. The code computed pertinent plant variables including temperatures, pressures, and power level.

This computer code is different than that used for the current licensing basis analysis where the LOFTRAN code is used. RETRAN has been approved by the NRC for the analysis of feedline break transients (Reference 2). The applicability of RETRAN to MPS3 for the SPU is addressed in Section 2.8.5.0.

The following four cases were analyzed for MPS3:

Case (1) Maximum reactivity feedback, with offsite power, 0.890 ft^2 break

Case (2) Maximum reactivity feedback, w/o offsite power, 0.890 ft^2 break

Case (3) Minimum reactivity feedback, with offsite power, 0.890 ft^2 break

Case (4) Minimum reactivity feedback, w/o offsite power, 0.890 ft^2 break

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the feedline break analysis. As stated in Section 2.8.5.2.4.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.2.4.2.4 Results

The results of the feedline break cases analyzed showed that all acceptance criteria noted above were met. No bulk boiling occurred in the primary coolant system following a feedline break prior to the time that the heat removal capability of the steam generators, being fed AFW, exceeded NSSS residual heat generation.

For MPS3, Case 1 was the limiting case. This case analyzed a feedline break with maximum reactivity feedback, offsite power available, and a break size of 0.890 ft^2. The transient results for this case are presented in Figures 2.8.5.2.4.1 through 2.8.5.2.4-7. The time sequence of events for this case is presented in Table 2.8.5.2.4-1.

The transient results for the similar Case 2, but with offsite power unavailable, are presented in Figures 2.8.5.2.4-8 through 2.8.5.2.4-14. This case models a feedline break with maximum reactivity feedback, offsite power unavailable, and a break size of 0.890 ft^2.

Numerical results of the SPU analysis along with a comparison to the previous analysis results are shown in Table 2.8.5.2.4-2. In all cases, the SPU analyses are more limiting than the previous analyses.

The results of the analyses performed for MPS3 at SPU conditions showed that for the postulated feedwater line rupture, AFW system capacity was adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core.

2.8.5.2.4.3 Conclusion

DNC has reviewed the analyses of feedwater system pipe breaks and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -27, -28, -31, and -35 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to feedwater system pipe breaks.

2.8.5.2.4.4 References

1. 10 CFR 50.67, Accident Source Term approved by NRC letter dated September 18, 2006 “Millstone Power Station, Unit No. 3 – Issuance of Amendment Re: Alternate Source Term (TAC No. MC3333)”.

2. WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, April 1999.

3. WCAP-14882-S1-P-A, RETRAN-02 Modeling and Qualification For Westinghouse Pressurized Water Reactors Non-LOCA Safety Analyses, Supplement 1 - Thick Metal Mass Heat Transfer Model and NOTRUMP-Based Steam Generator Mass Calculation Method, October 2005.

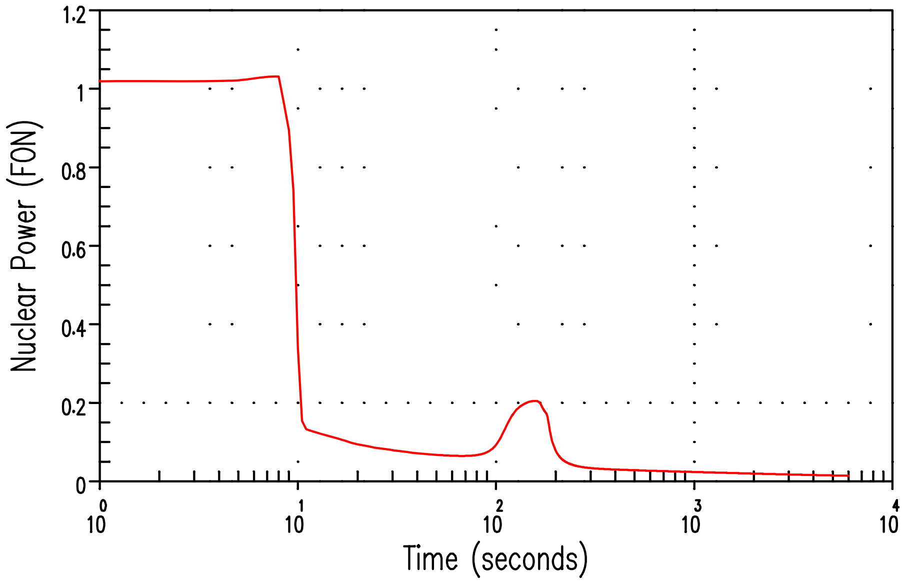
Table 2.8.5.2.4-1
Time Sequence of Events – Major Rupture of a Main Feedwater Pipe

Case	Event	Time (sec)
Feedline Rupture with Maximum Reactivity Feedback, Offsite Power Available, Break Size of 0.890 ft^2	Main feedline rupture occurs	0.0
	Low-low steam generator water level reactor trip setpoint reached in ruptured steam generator	5.5
	Rods begin to drop	7.5
	Auxiliary feedwater flow initiation to the intact steam generators occurs	65.5
	Low pressurizer pressure safety injection setpoint reached	82.3
	Safety injection flow initiation occurs	131.3
	Low steamline pressure setpoint reached in ruptured steam generator	169.2
	All main steamline isolation valves close	181.2
	Pressurizer safety valve setpoint reached	496.0
	First steam generator safety valve setpoint reached in intact steam generators	668.6
	Minimum margin to hot leg saturation occurs	5064.5
	Hot and cold leg temperatures begin to decrease	~5100

Table 2.8.5.2.4-2
Major Rupture of a Main Feedwater Pipe - Results and Comparison to Previous Results

	SPU Analysis	Previous Analysis	Limit
Minimum Margin to Boiling in the Hot Leg (°F)	2.4	22	0

Figure 2.8.5.2.4-1
Feedline Break with Offsite Power, Nuclear Power and Core Heat Flux vs. Time



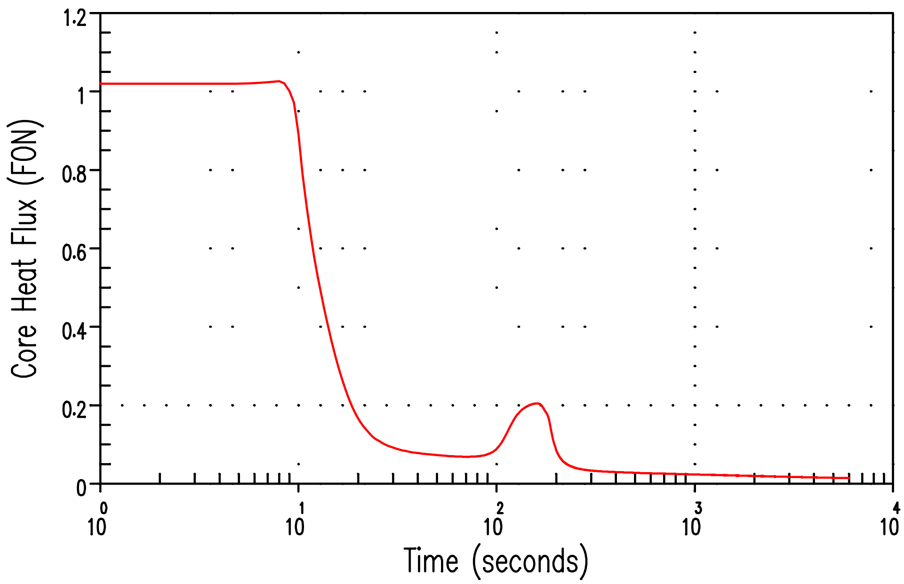
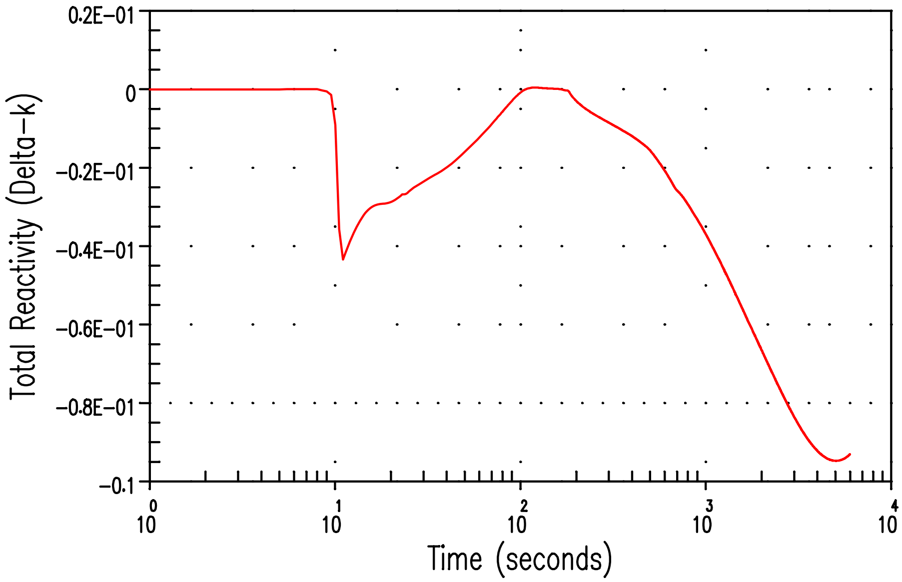


Figure 2.8.5.2.4-2
Feedline Break with Offsite Power, Total Reactivity and Total RCS Flow vs. Time



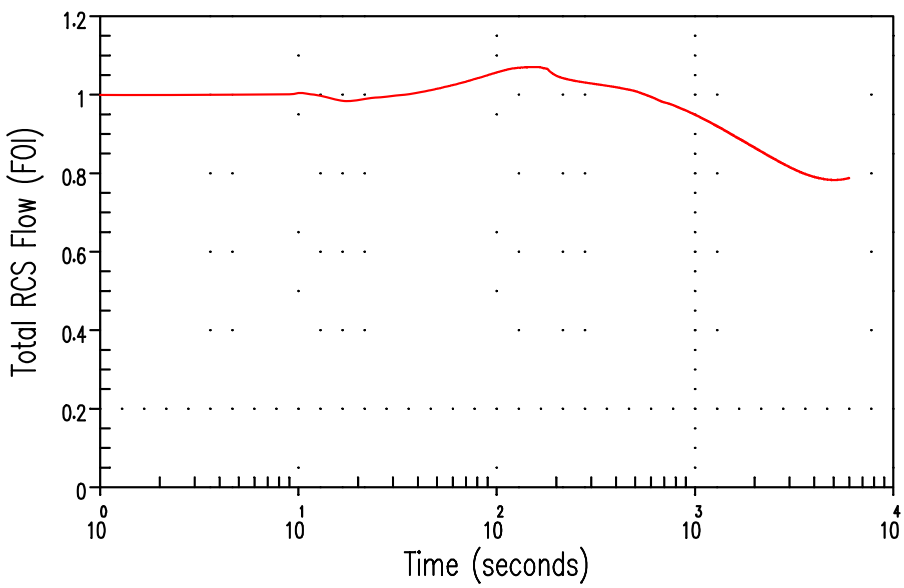
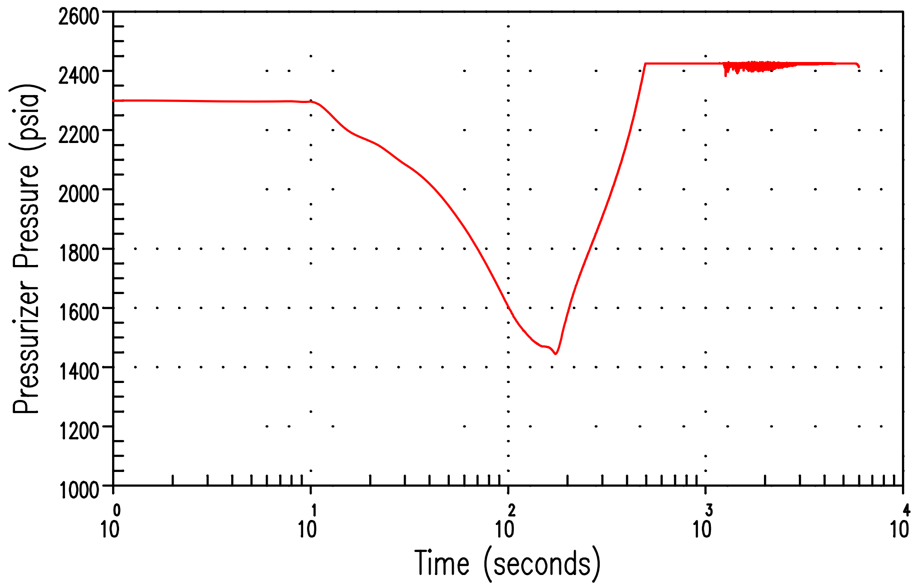


Figure 2.8.5.2.4-3
Feedline Break with Offsite Power, Pressurizer Pressure and Pressurizer Water Volume vs. Time



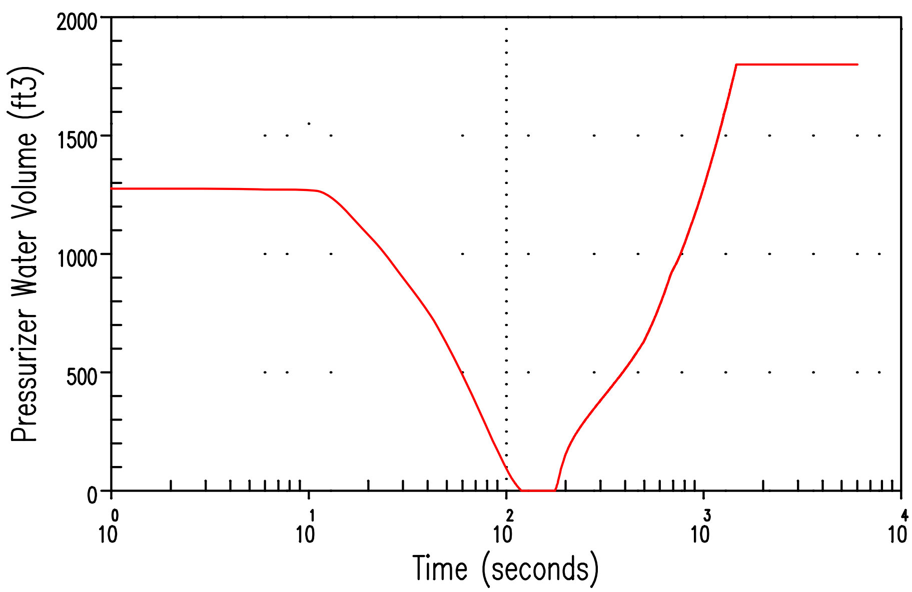
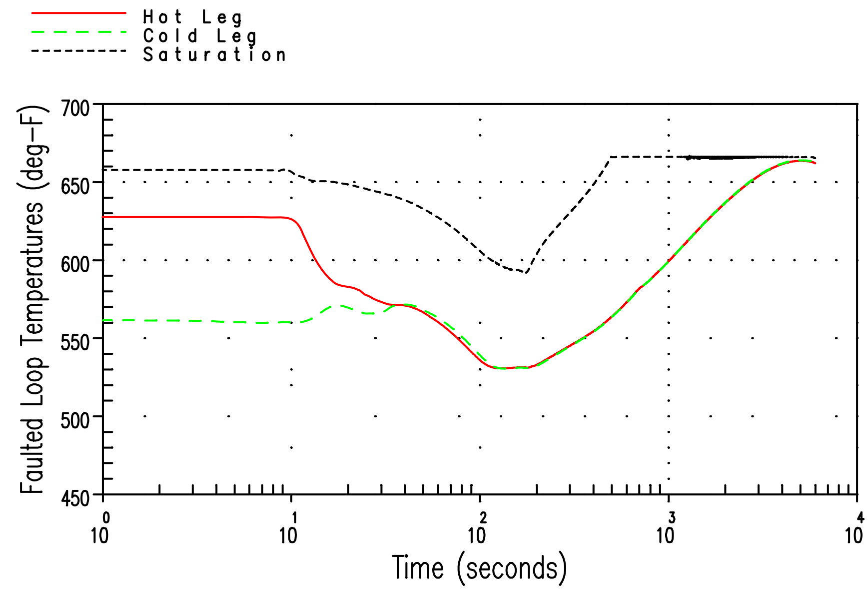


Figure 2.8.5.2.4-4
Feedline Break with Offsite Power, Reactor Coolant Temperatures vs. Time for the Faulted and Intact Loops



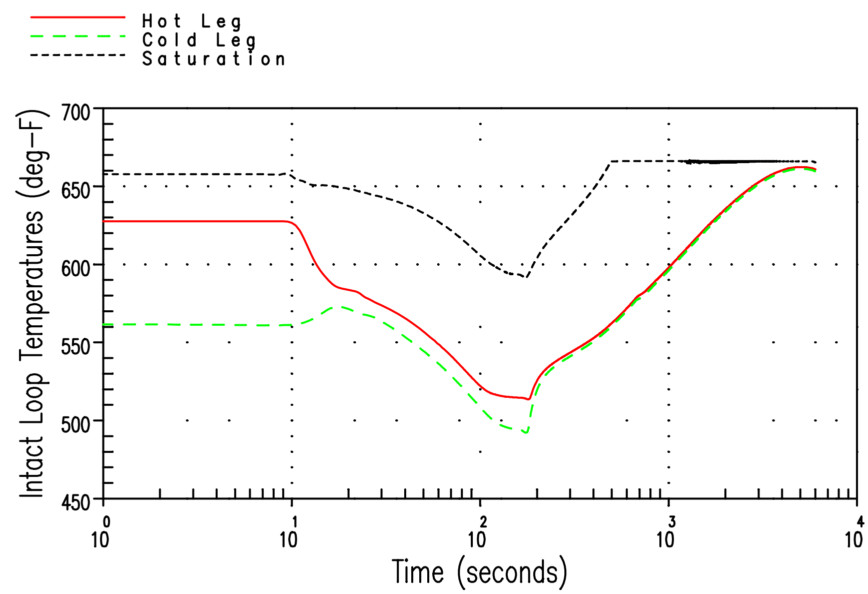
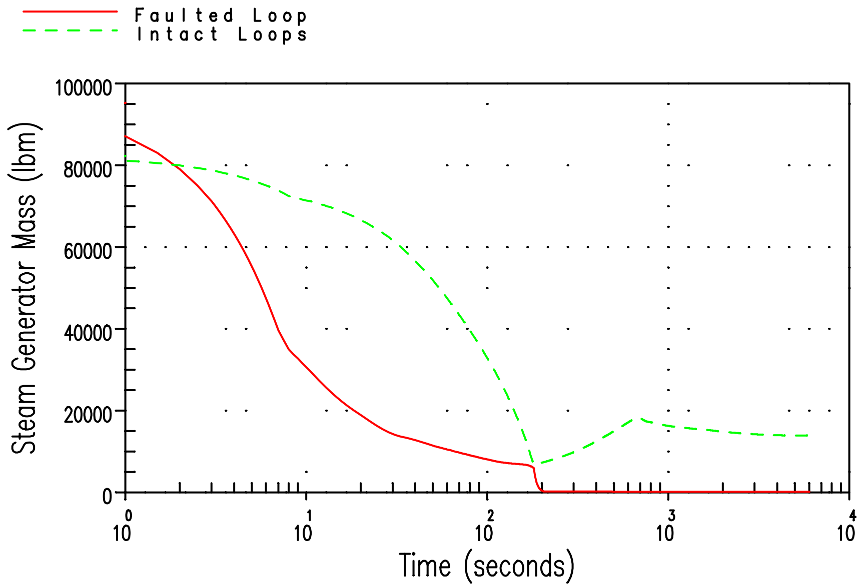


Figure 2.8.5.2.4-5
Feedline Break with Offsite Power, Steam Generator Mass and Steam Generator Pressure vs. Time



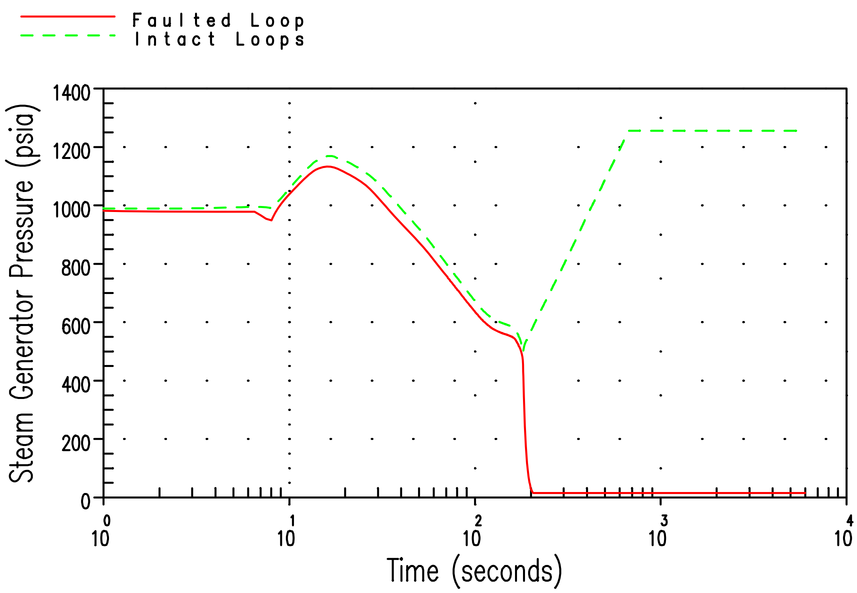
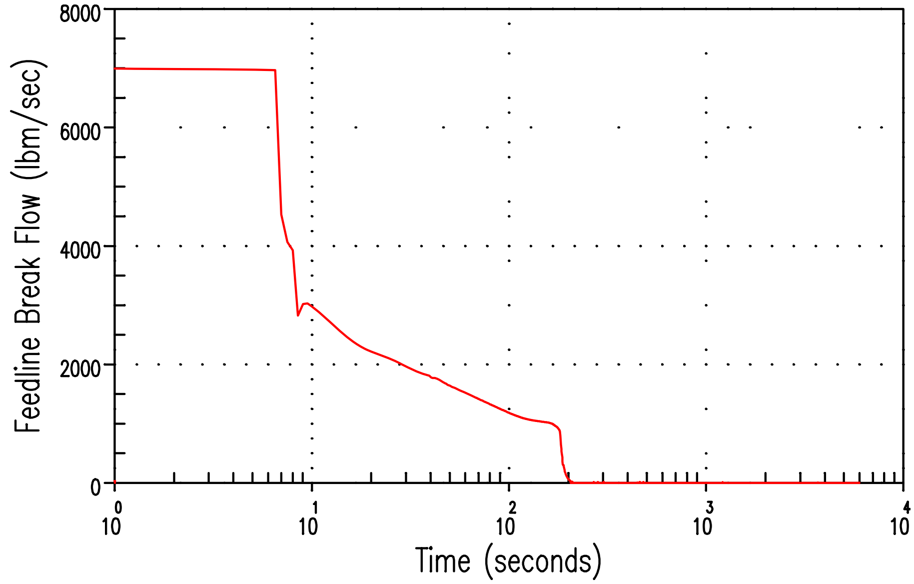


Figure 2.8.5.2.4-6
Feedline Break with Offsite Power, Feedline Break Flow and Enthalpy vs. Time



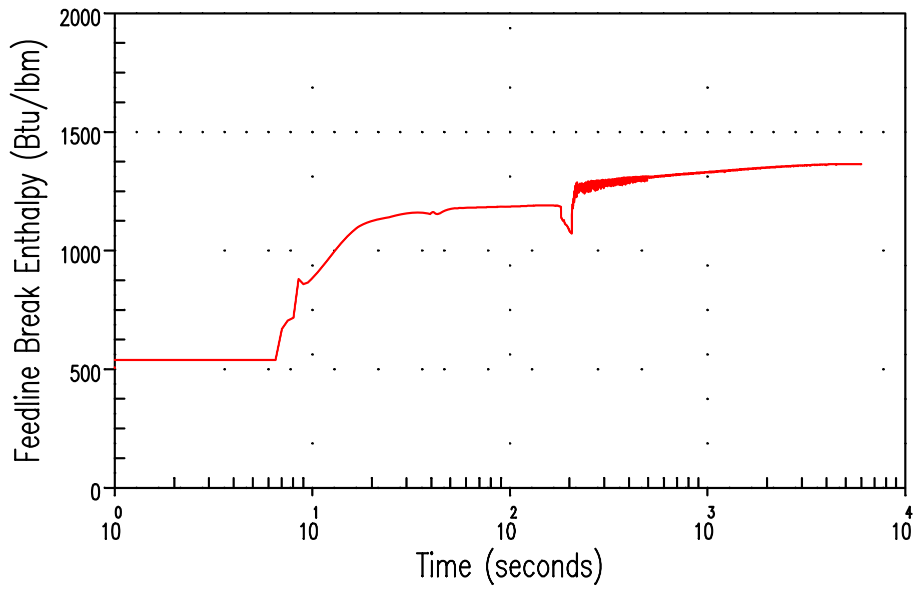


Figure 2.8.5.2.4-7
Feedline Break with Offsite Power, Auxiliary Feedwater Flow vs. Time

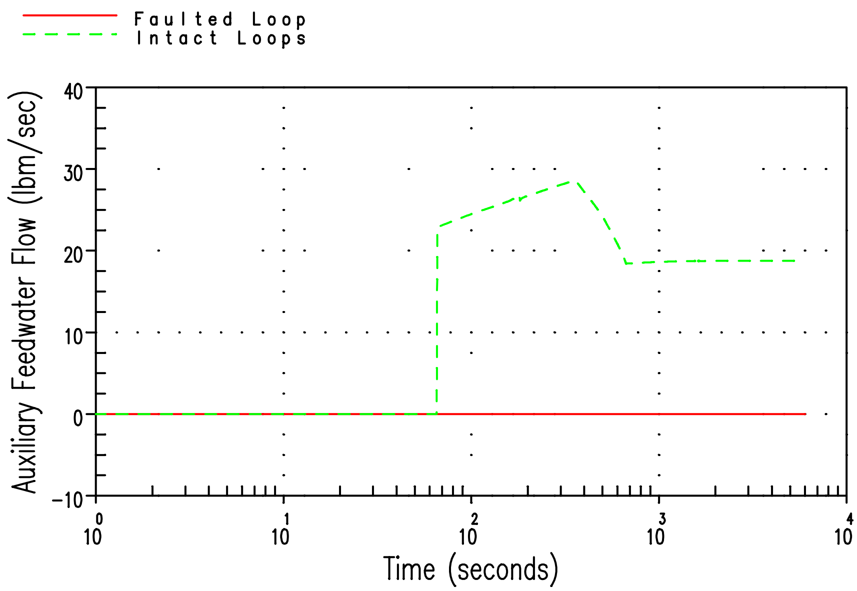
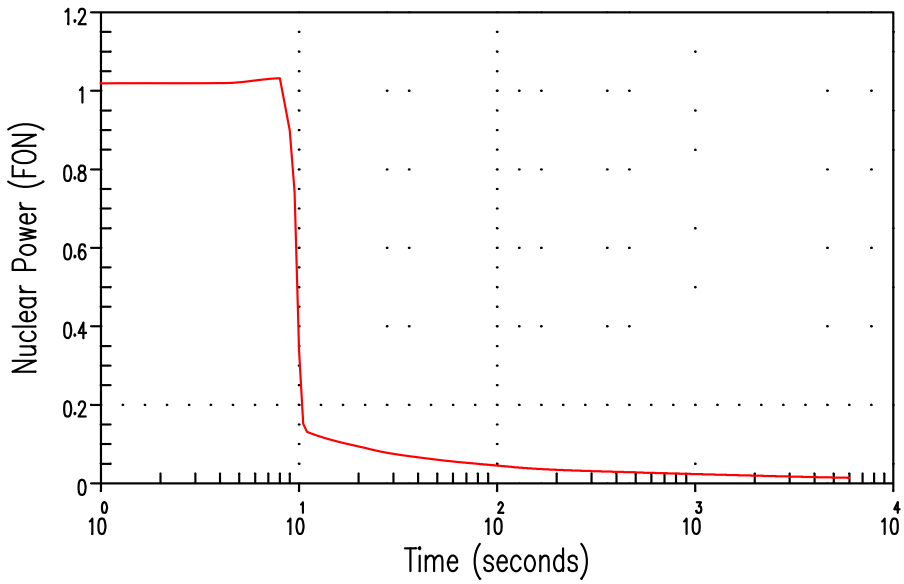


Figure 2.8.5.2.4-8
Feedline Break without Offsite Power, Nuclear Power and Core Heat Flux vs. Time



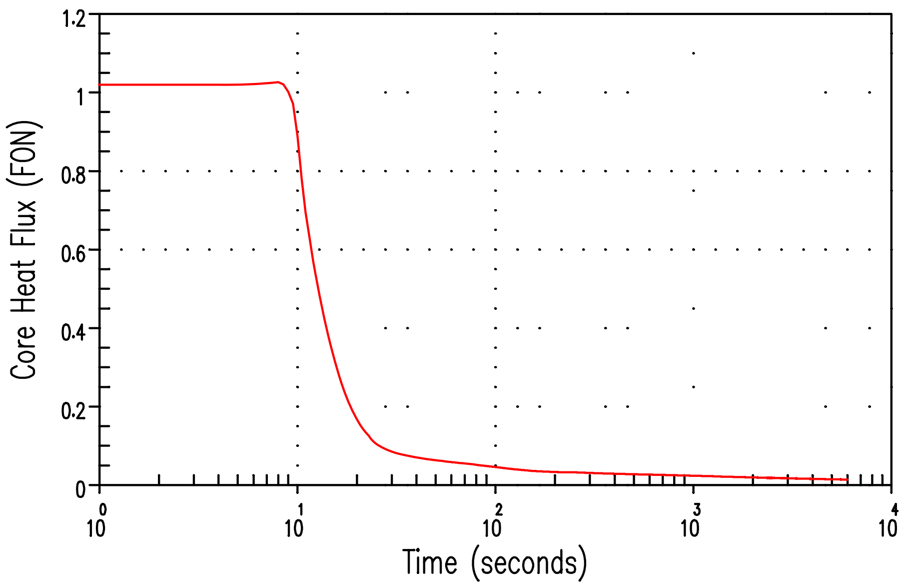


Figure 2.8.5.2.4-9
Feedline Break without Offsite Power, Total Reactivity and Total RCS Flow vs. Time

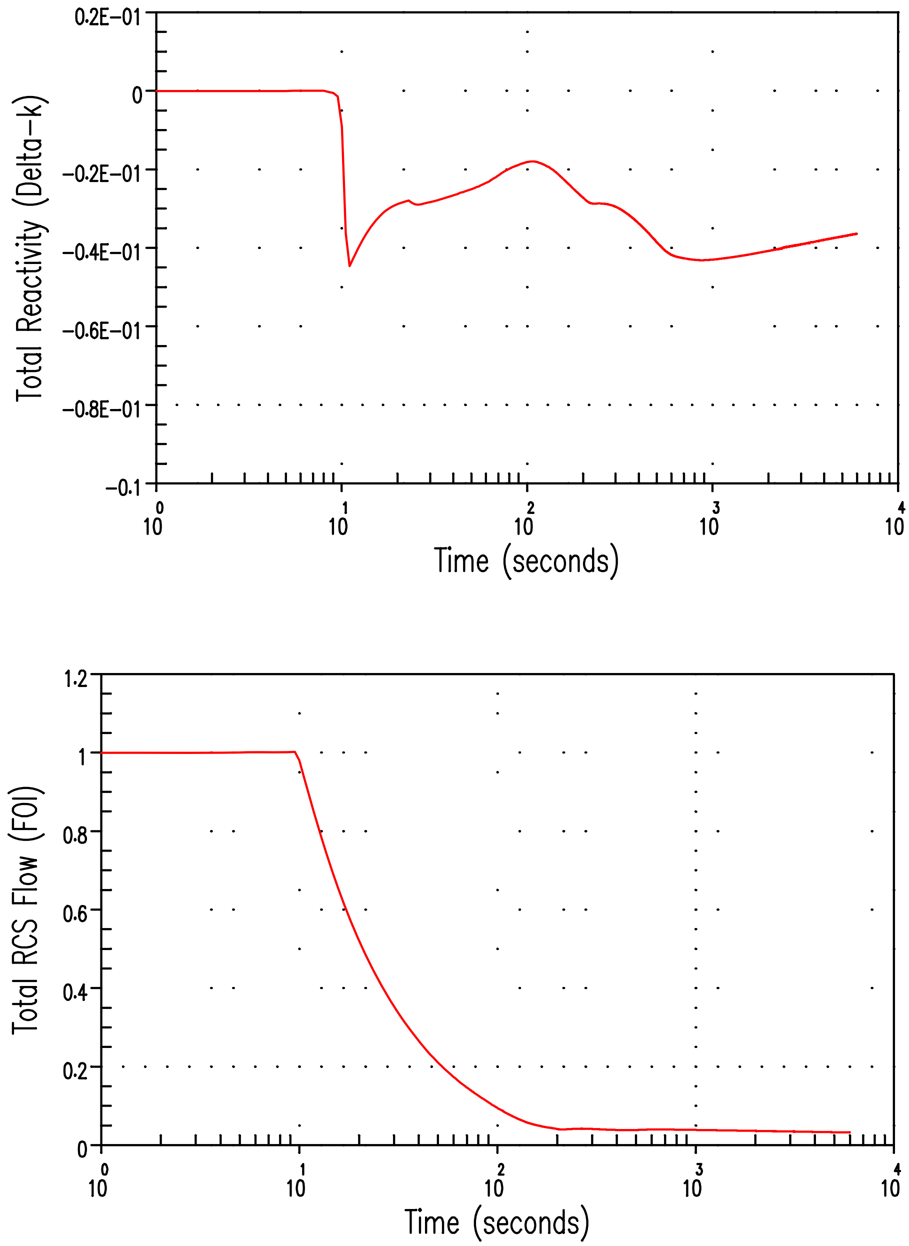
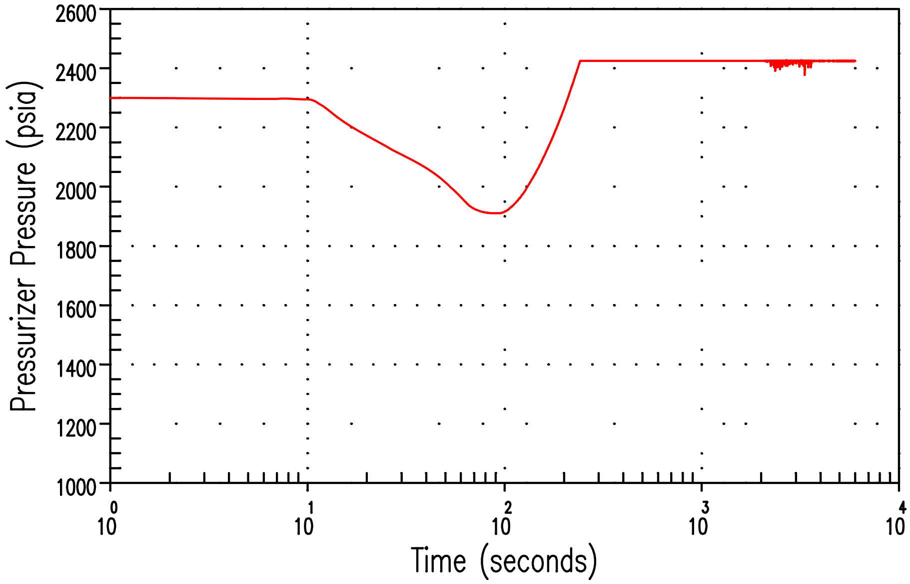


Figure 2.8.5.2.4-10
Feedline Break without Offsite Power, Pressurizer Pressure and Pressurizer Water Volume vs. Time



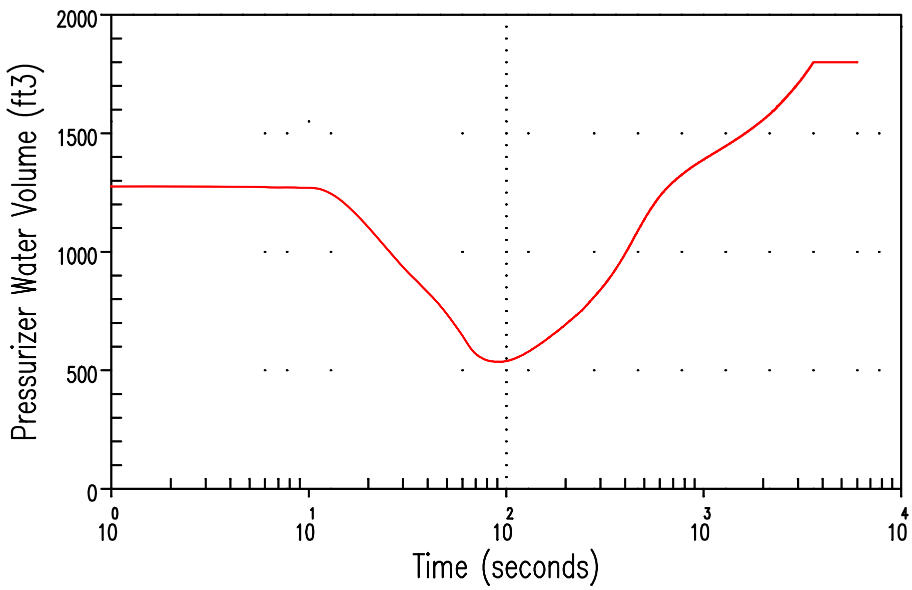
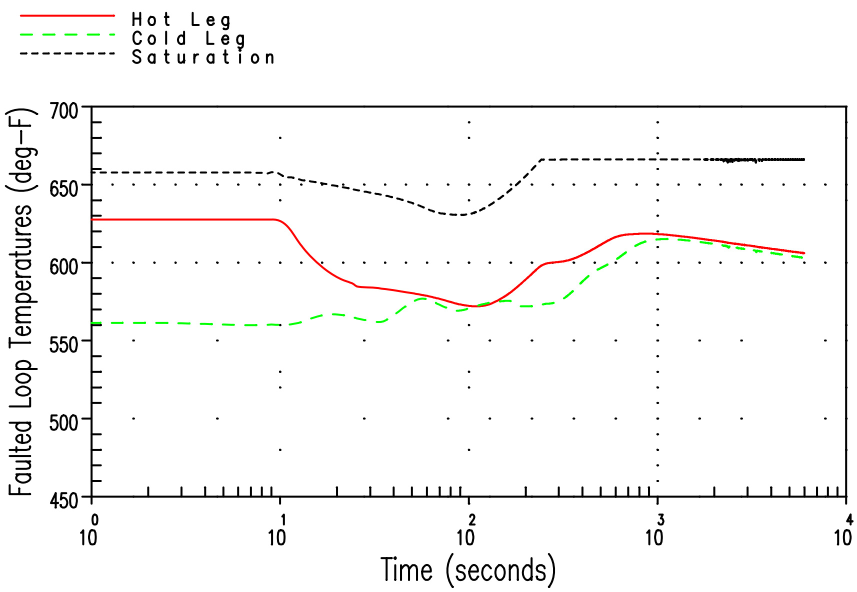


Figure 2.8.5.2.4-11
Feedline Break without Offsite Power, Reactor Coolant Temperatures vs. Time for the Faulted and Intact Loops



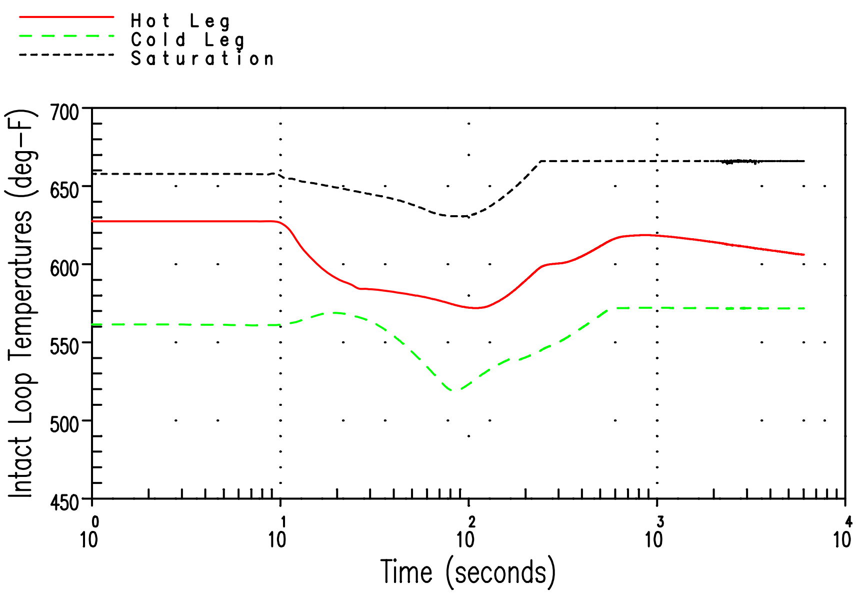
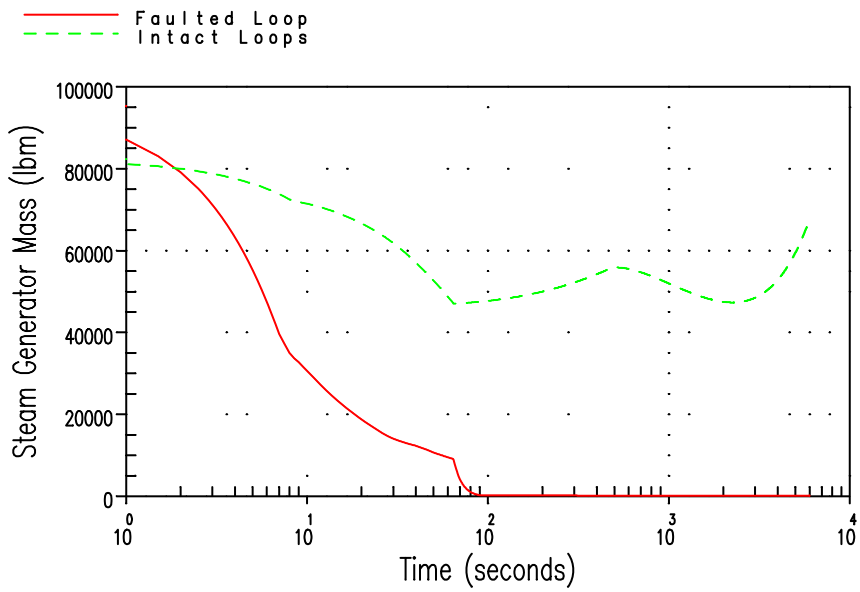


Figure 2.8.5.2.4-12
Feedline Break without Offsite Power, Steam Generator Mass and Steam Generator Pressure vs. Time



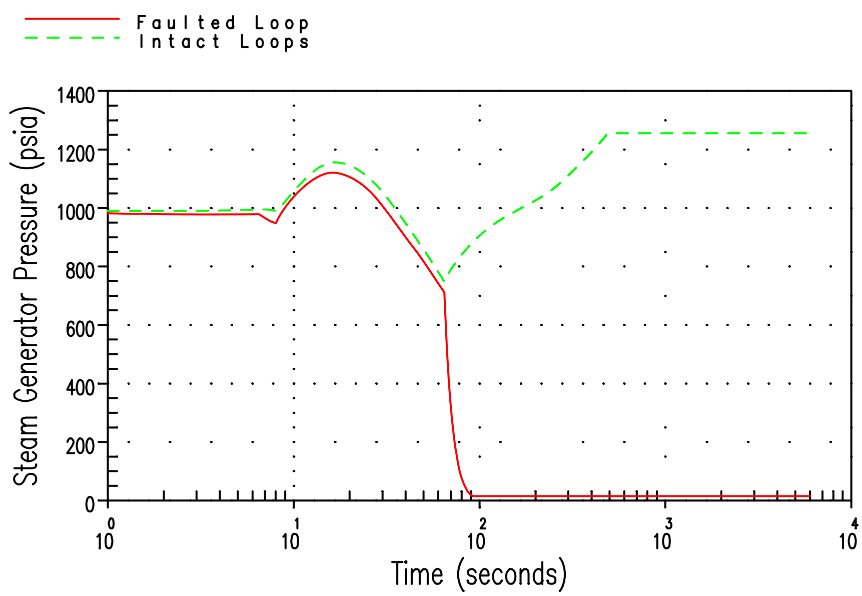
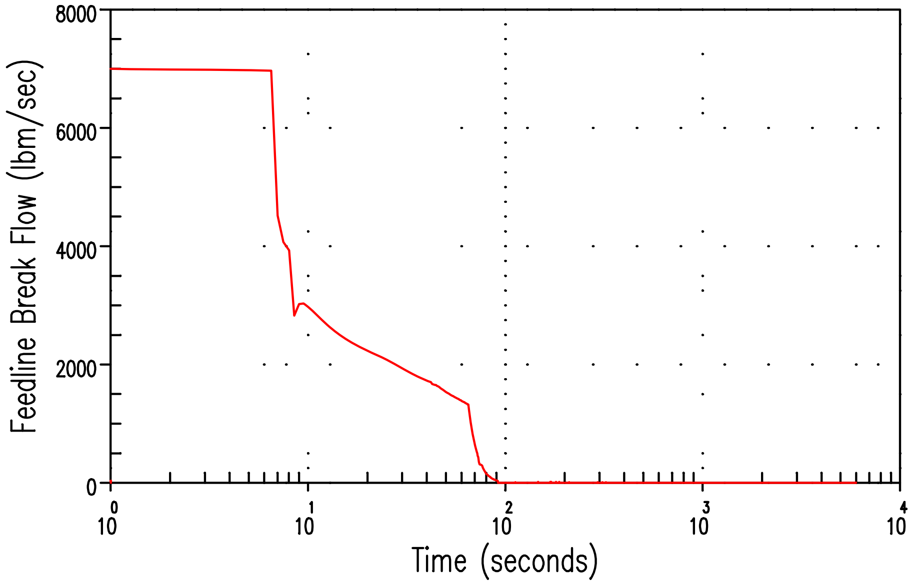


Figure 2.8.5.2.4-13
Feedline Break without Offsite Power, Feedline Break Flow and Enthaply vs. Time



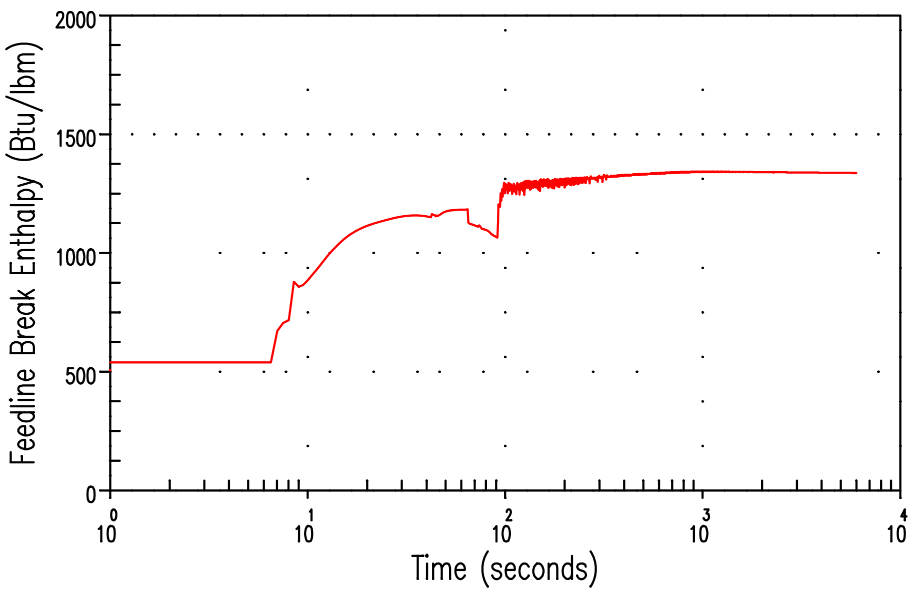
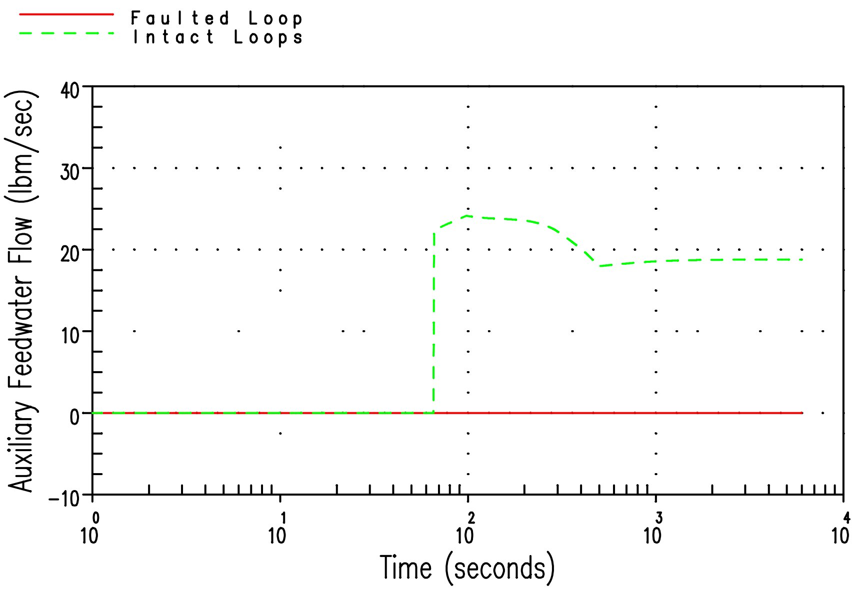


Figure 2.8.5.2.4-14
Feedline Break without Offsite Power, Auxiliary Feedwater Flow vs. Time



2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

2.8.5.3.1.1 Regulatory Evaluation

A decrease in RC flow occurring while the plant is at power could result in a degradation of core heat transfer. An increase in fuel temperature and accompanying fuel damage could then result if specified acceptable fuel design limits (SAFDLs) are exceeded during the transient. Reactor protection and safety systems are actuated to mitigate the transient.

The DNC review covered:

- The postulated initial core and reactor conditions
- The methods of thermal and hydraulic analyses
- The sequence of events
- The assumed reactions of reactor system components
- The functional and operational characteristics of the RPS
- Operator actions
- The results of the transient analyses

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including anticipated operational occurrences (AOOs)
- GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation
- GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded

Specific review criteria are contained in SRP Section 15.3.1-2, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 15.3.1-2, Rev. 1.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to:

- GDC-10, Reactor design, is described in FSAR Section 3.1.2.10.

The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant clean up system to mitigate, and are consistent with plant design bases.

2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

   Note that the term "fuel damage" as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

   FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-15, Reactor Coolant System Design, is described in FSAR Section 3.1.2.15.

  The design pressure and temperature for each component in the reactor coolant and associated auxiliary, control, and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

  Additionally, reactor coolant pressure boundary components achieve a large margin of safety by the use of proven ASME materials and design codes, the use of proven fabrication techniques, nondestructive shop testing, and integrated hydrostatic testing of assembled components. FSAR Chapter 5 discusses the RCS design.

- GDC-26, Reactivity Control System Redundancy and Capability, is described in FSAR Section 3.1.2.26.

  Two reactivity control systems are provided. They are the RCCAs and chemical shim (boric acid). The RCCAs are inserted into the core by the force of gravity.

  During operation, the shutdown rod banks are fully withdrawn. The rod control system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specific fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses, and the most reactive rod cluster is assumed to be in the fully withdrawn position.

The CVCS maintains the reactor in the cold shutdown state independent of the position of the control rods. It can compensate for xenon burnout transients.

FSAR Chapter 4 presents details of the construction of the RCCAs. FSAR Chapter 7 discusses their operation. FSAR Chapter 9 describes the means of controlling boric acid concentration.

FSAR Section 15.3.1.1 addresses the impact of a partial loss of RCS flow. A partial loss of coolant flow accident can result from a mechanical or electrical failure in a RCP, or from a fault in the power supply to the pump or pumps supplied by a RCP bus. If the reactor is at power at the time of the accident, the immediate effect of loss-of-coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor is not tripped promptly. It is classified as an ANS Condition II event.

FSAR Section 15.3.1.1 also states that the necessary protection against a partial loss-of-coolant flow accident is provided by the low primary coolant flow reactor trip signal, which is actuated in any reactor coolant loop by two out of three low flow signals.

FSAR Section 15.3.1.2 states that one case has been analyzed for the loss of one pump with four loops in operation. This transient is analyzed by three digital computer codes. First, the LOFTRAN (WCAP-7907-P-A) code is used to calculate the loop and core flow during this transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The FACTRAN (WCAP-7908-A, 1989) Code is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the THINC code (See FSAR Section 4.4) is used to calculate the DNBR during the transient based on the heat flux from FACTRAN and flow from LOFTRAN.

FSAR Table 15.3-1 shows the calculated sequence of events for this transient. FSAR Table 15.0-6 lists plant systems and equipment that are necessary to mitigate the effects of the accident. FSAR Section 15.3.1.3 concludes that the analysis shows that DNBR does not decrease below the limit value at any time during the transient. Thus, no fuel or clad damage is predicted, and all applicable acceptance criteria are met.

FSAR Section 15.3.2 addresses the impact of a complete loss of forced RC flow. A complete loss of forced RC flow may result from a simultaneous loss of electrical supplies to all RCPs, or to a grid frequency decay. (The underfrequency condition is addressed below.) If the reactor is at power at the time of the accident, the immediate effect of loss-of-coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor were not tripped promptly. It is classified as an ANS Condition III event.

The protection against a complete loss-of-flow accident is provided by the RCP underspeed and low RC loop flow reactor trips. Above Permissive 8, low flow in any loop actuates a reactor trip. Between approximately 10 percent power (Permissive 7) and approximately 50 percent power

(Permissive 8), low flow in any two loops actuates a reactor trip. The reactor trip on RCP underspeed is provided to protect against conditions which can cause a loss of voltage to all RCPs, i.e., loss of non-emergency AC power. The reactor trip on RCP underspeed is also provided to trip the reactor for an underfrequency condition, resulting from frequency disturbances on the power grid. This function is blocked below approximately 10 percent power (Permissive 7).

FSAR Section 15.3.2.2 states that a case has been analyzed for the loss of four RCPS with four loops in operation. The same computer codes, method of analysis and reactivity coefficients are used for the complete loss of flow transient as for the partial loss of flow transient, except that the reactor trip is actuated by RCP underspeed.

FSAR Table 15.3-1 shows the calculated sequence of events for this transient. Figure 15.3-8 shows that the calculated DNBR is always equal to or greater than the limit value, for the loss of all four RCPs (four RCPs coasting down) with a reactor trip on an underspeed signal. Thus, no fuel or clad damage is predicted, and all acceptance criteria are met.

FSAR Section 15.3.2.3 states that a case has been analyzed where the complete loss of forced primary coolant flow resulted from a reduction in RCP motor supply frequency. The same signals which provide the necessary protection against a complete loss of flow provide for protection in an underfrequency event. The analysis is the same as that for the complete loss of flow with the exception of the simulation of the frequency decay. Rather than the RCPs coasting down freely, the decrease in electrical frequency (5 Hz/sec) decelerates the RCPs faster than a loss of power.

FSAR Table 15.3-1 shows the calculated sequence of events for this transient. Figure 15.3-16 shows that the calculated DNBR is always equal to or greater than the limit value, for the frequency decay to all four RCPs with a reactor trip on an underspeed signal.

Westinghouse NSALs -02-3 Rev. 01; -02-4 Rev. 0 and –02-05 Rev. 01 concerning SG level errors from mid-deck plate issue, were reviewed for their impacts on the current licensing basis regarding this transient. These NSALs do not impact this transient.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Decrease in reactor coolant system flow and other transient analyses are not within the scope of License Renewal.

2.8.5.3.1.2 Technical Evaluation

The specific acceptance criteria for this event are as follows:

- The departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit at all times during the transient. Demonstrating that the DNBR limit is met satisfies the requirements of GDC-10.
- Primary and secondary pressures remain below 110 percent of their respective design pressures at all times during the transient. Demonstrating that the primary and secondary pressure limits are met satisfies the requirements of GDC-15.

- GDC-26 requires reliable control of reactivity changes to ensure that specified acceptable fuel design limits are not exceeded, including anticipated operational occurrences. This is accomplished by ensuring that appropriate margin for malfunctions, such as stuck rods, are accounted for in the safety analysis assumptions. Demonstrating that the fuel design limits (i.e., DNBR) are met satisfies the requirements of GDC-26.

The discussion below demonstrates that all applicable acceptance criteria are met for this event at MPS3 at SPU conditions.

2.8.5.3.1.2.1 Introduction

A loss of forced coolant flow accident (FSAR Sections 15.3.1 and 15.3.2) can result from a mechanical or electrical failure in an RCP, from an interruption in the power supplying one or more of these pumps, or from a reduction in RCP motor supply frequency. If the reactor is at power at the time of the event, the immediate effect from the loss of forced coolant flow is a rapid increase in the coolant temperature. This increase in coolant temperature could result in a violation of the DNBR limit, with subsequent fuel damage, if the reactor is not promptly tripped.

The following signals provide protection against a loss of forced reactor coolant flow incident:

- Low reactor coolant loop (RCL) flow
- RCP Underspeed

The reactor trip on low reactor coolant loop flow provides primary protection against partial loss-of-flow conditions. This function is generated by two-out-of-three low-flow signals in any RCL. Above Permissive P-8, low flow in any loop actuates a reactor trip. Between approximately 10 percent power (Permissive P-7) and the power level corresponding to Permissive P-8, low flow in two loops actuates a reactor trip. Reactor trip on low flow is blocked below Permissive P-7.

The reactor trip on RCP underspeed provides primary protection following a complete loss of power to the RCPs or a major electrical frequency disturbance. An RCP shaft speed below the underspeed setpoint trips the reactor. The underspeed trip function is blocked below Permissive P-7.

2.8.5.3.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The loss of reactor coolant flow accident was analyzed using the Revised Thermal Design Procedure (RTDP) (Reference 1). Initial core power was assumed to be at its nominal value consistent with steady-state, full-power operation. The RCS pressure and vessel average temperature were assumed to be at their nominal values. Minimum measured flow was also assumed. Uncertainties in initial conditions were accounted for in the DNBR limit value as described in the RTDP.

A conservatively large absolute value of the Doppler-only power coefficient was used. The analysis also assumed a conservative moderator temperature coefficient (MTC) of zero pcm/°F at hot full power (HFP) conditions. This resulted in the maximum core power and hot spot heat flux during the initial part of the transient when the minimum DNBR is reached.

The only safety system that provides mitigation for a Loss of Reactor Coolant Flow event is a reactor trip. The engineered safety systems (e.g., safety injection) are not required to function. Therefore, the limiting single failure assumed was the failure of one line of reactor trip protection. However, due to the redundancy designed into the protection system, this does not prevent or delay the reactor trip. As such, there is no single failure which yields more limiting analysis results.

A partial loss of forced reactor coolant flow incident is classified by the ANS as a Condition II event. A complete loss of forced reactor coolant flow incident is classified by the ANS as a Condition III event; however, for conservatism, the incident was analyzed to Condition II criteria. The immediate effect from a complete loss of forced reactor coolant flow is a rapid increase in the reactor coolant temperature and subsequent increase in RCS pressure. The following three items identify the acceptance criteria associated with the analysis of the loss of flow events:

- The critical heat flux is not to be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressures in the RCS and main steam system (MSS) are maintained below 110 percent of their respective design pressures.
- The peak linear heat generation rate does not exceed a value that would cause fuel centerline melt.

2.8.5.3.1.2.3 Description of Analyses and Evaluations

The following loss of forced reactor coolant flow cases were analyzed for SPU conditions:

- Loss of power to one RCP (partial loss of flow)
- Loss of power to all RCPs (complete loss of flow)
- 5 Hz/second frequency decay of the RCPs power supply (complete loss of flow)

In addition to the above cases, a partial loss of flow (loss of power to one RCP) was performed at 60 percent power without a reactor trip to verify the Permissive P-8 setpoint. The analysis assumed a P-8 setpoint of 50 percent of nominal power, plus a 10 percent allowance.

The transients were analyzed with two computer codes. First, the RETRAN computer code (Reference 2) was used to calculate the loop and core flows during the transient, the time of reactor trip based on the calculated RCP speed, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE computer code (Reference 3) was then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN. The DNBR transients presented represent the minimum of the typical or thimble cell for the fuel.

These computer codes are different than those used for the current licensing basis analysis where the LOFTRAN (WCAP-7907-P-A), FACTRAN (WCAP-7908-A, 1989) and THINC codes are used. RETRAN and VIPRE have been approved by the NRC for the analysis of Loss of Forced Reactor Coolant Flow (Reference 2 and 3). The applicability of the RETRAN and VIPRE codes to MPS3 for the SPU is discussed in Section 2.8.5.0. In particular, as documented in Reference 2, the RETRAN flow coastdown results were shown to compare favorably to

LOFTRAN code results such that, in that respect, RETRAN is considered equivalent to LOFTRAN.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the loss of forced reactor coolant flow analysis. As stated in Section 2.8.5.3.1.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.3.1.2.4 Results

The two complete loss of flow cases were assumed to trip on an RCP underspeed reactor trip signal, and the partial loss of flow case was assumed to trip on a low reactor coolant flow reactor trip signal. The VIPRE (Reference 3) analysis for these scenarios confirmed that the minimum DNBR acceptance criterion for the WRB-2M correlation was met. Fuel cladding damage criteria were not challenged in either of the complete loss of forced reactor coolant flow cases since the DNB criterion was met.

The analysis of the complete loss of flow event also demonstrated that the peak RCS and MSS pressures were well below their respective limits.

The more limiting of these two cases in terms of the minimum calculated DNBR was the frequency decay case. The transient results for this case are presented in Figure 2.8.5-1 through 2.8.5-3. The sequence of events for each case is presented in Table 2.8.5.3.1-1. Numerical results for the SPU analysis are shown in Table 2.8.5.3.1-2.

The most limiting of the loss of flow cases with respect to the peak primary system pressure was the frequency decay event, which resulted in a maximum pressure of only 2410 psia. The secondary side pressure in all cases remained approximately constant at the initial value of 963 psia until the reactor trip. Following the trip, the pressure slowly rises due to the loss of steam flow to the turbine, eventually reaching the steam system safety valve setpoint. Therefore, the maximum secondary side pressure does not exceed the safety valve setpoint.

The analysis performed for the SPU demonstrates that, for the aforementioned loss of flow cases, the DNBR did not decrease below the safety analysis limit value at any time during the transients; thus, no fuel or cladding damage is predicted. The peak primary and secondary system pressures remained below their respective limits at all times. All applicable acceptance criteria were therefore met.

For the case of the partial loss of flow from 60 percent power with no reactor trip, the VIPRE results showed that the minimum DNBR acceptance criterion was also met for this case, thereby verifying the P-8 trip setpoint of 50 percent power.

The protection features presented in Licensing Report Section 2.8.5.3.1.2.1 provide mitigation for the loss of forced reactor coolant flow transients such that the above criteria are satisfied. Furthermore, the results and conclusions of this analysis are confirmed on a cycle-specific basis as part of the normal reload process.

2.8.5.3.1.3 Conclusion

DNC has reviewed the analyses of the decrease in reactor coolant flow event and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the decrease in reactor coolant flow event.

2.8.5.3.1.4 References

1. WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, Friedland, A. J. and Ray, S., April 1989.

2. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999.

3. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999.

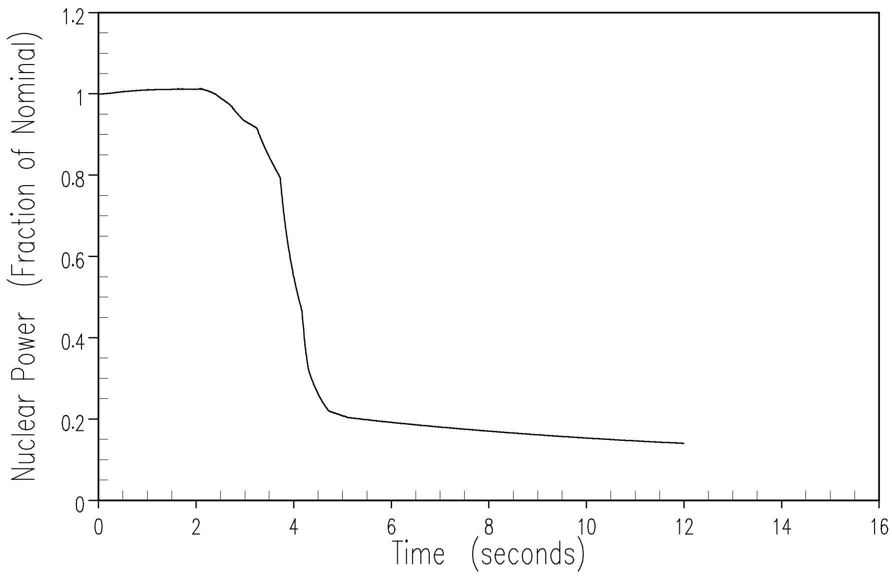
Table 2.8.5.3.1-1
Time Sequence of Events – Loss of Forced Reactor Coolant Flow

Case	Event	Time (sec)
5 Hz/sec Frequency Decay of the RCPs Power Supply	Frequency Decay Begins	0.0
	Low RCP Speed Setpoint Reached	1.0
	Rods Begin to Drop	1.6
	Minimum DNBR Occurs	3.7
	Maximum Primary Pressure Occurs	4.1
Loss of Power to One RCP	Flow Coastdown Begins	0.0
	Reactor Coolant Low-Flow Setpoint Reached	1.7
	Rods Begin to Drop	2.7
	Minimum DNBR Occurs	3.6
	Maximum Primary Pressure Occurs	4.5
Loss of Power to All RCPs	Flow Coastdown Begins	0.0
	Low RCP Speed Setpoint Reached	0.9
	Rods Begin to Drop	1.5
	Minimum DNBR Occurs	3.3
	Maximum Primary Pressure Occurs	3.9

Table 2.8.5.3.1-2
SPU Loss of Forced Reactor Coolant Flow Results

	Analysis Value	Limit Value
Minimum DNBR – Single RCP Coasting Down	2.120	1.60
Minimum DNBR – All RCPs Coasting Down	1.815	1.60
Minimum DNBR – Frequency Decay on All RCPs	1.737	1.60

Figure 2.8.5-1
Loss of Forced Reactor Coolant Flow - Frequency Decay
Nuclear Power and Loop Flow Rate vs. Time



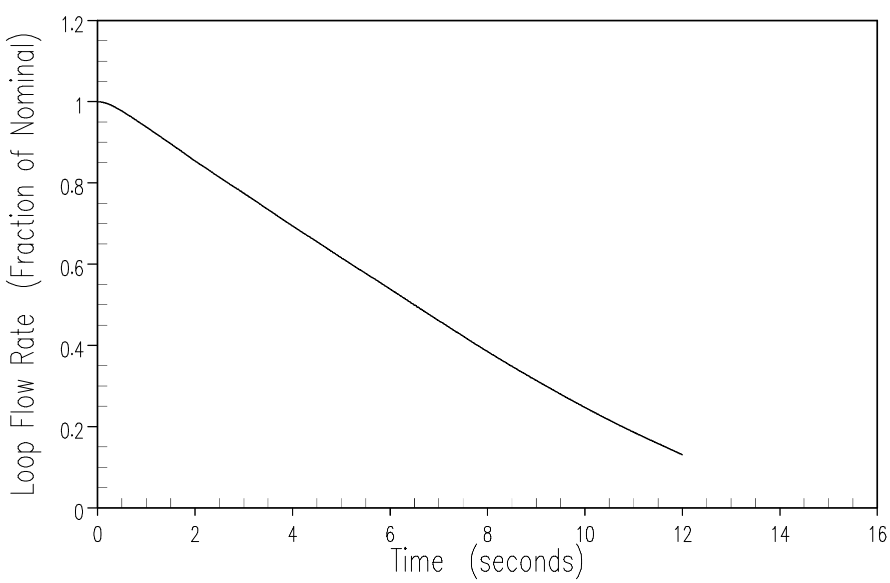
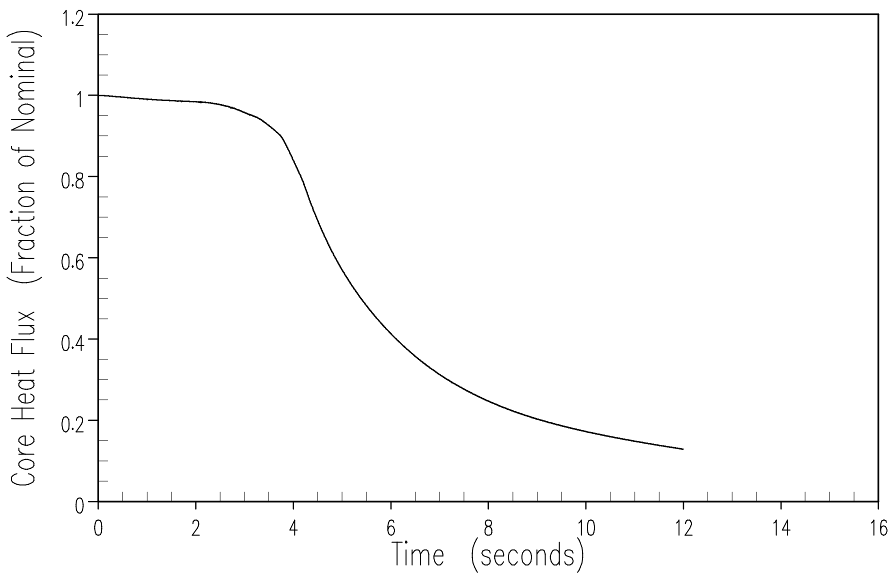


Figure 2.8.5-2
Loss of Forced Reactor Coolant Flow - Frequency Decay
Core and Hot Channel Heat Flux vs. Time



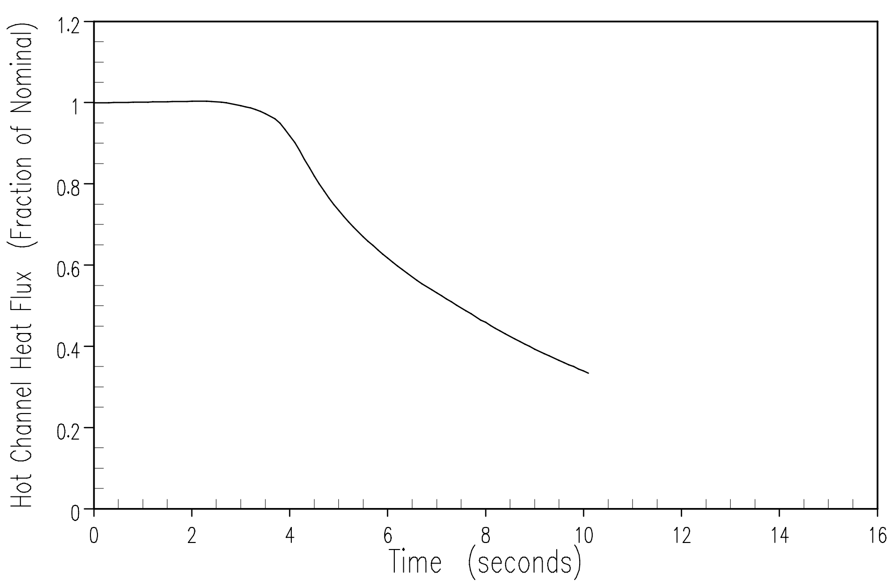
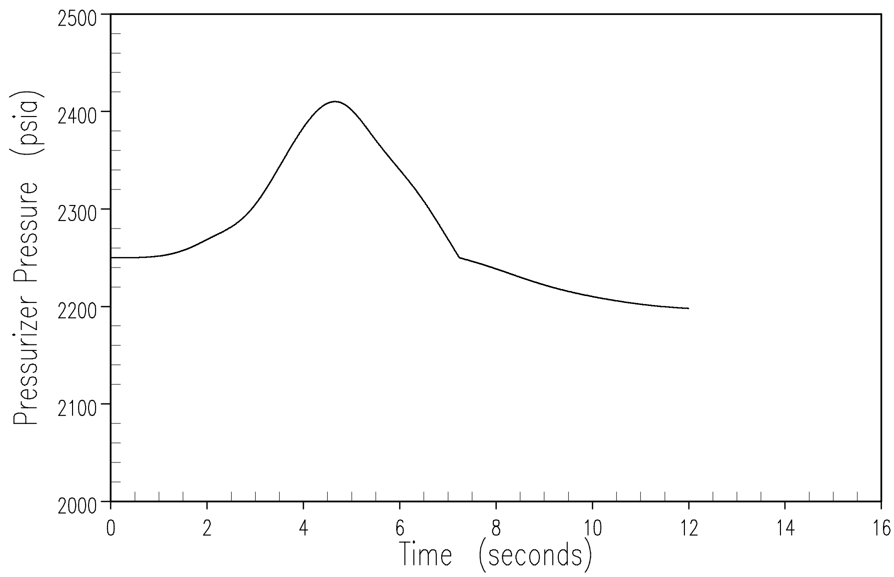
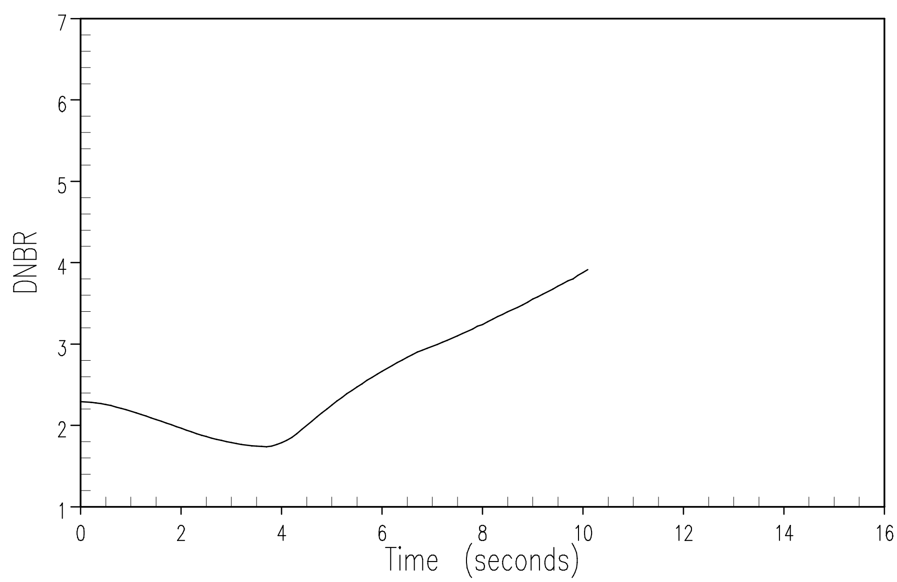


Figure 2.8.5-3
Loss of Forced Reactor Coolant Flow - Frequency Decay
Pressurizer Pressure and DNBR vs. Time





2.8.5.3.2 Reactor Coolant Pump Rotor Seizure and RCP Shaft Break

2.8.5.3.2.1 Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of a RCP. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the plant is at power results in a degradation of core heat transfer, which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient.

The DNC review covered:

- The postulated initial and long-term core and reactor conditions
- The methods of thermal and hydraulic analyses
- The sequence of events
- The assumed reactions of reactor system components
- The functional and operational characteristics of the RPS
- Operator actions
- The results of the transient analyses

The acceptance criteria are based on:

- GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained
- GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core
- GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized

Specific review criteria are contained in the SRP, Section 15.3.3-4, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), Section 15.3.3-4, Rev. 2.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to:

- GDC-27, Combined Reactivity Control Systems Capability, is described in FSAR Section 3.1.2.27.

  MPS3 is provided with means for making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. FSAR Chapters 4 and 9 discuss these means in detail. Combined use of the rod cluster control system and the chemical shim control system permit the necessary shutdown margin to be maintained during long term xenon decay and plant cooldown. The single highest worth control cluster is assumed to be stuck full-out upon trip for this determination. FSAR Chapter 15 describes accident assumptions in detail.

- GDC-28, Reactivity Limits, is described in FSAR Section 3.1.2.28.

  The maximum reactivity worth of control rods and the maximum rate of reactivity insertion employing control rods are limited to values that prevent rupture of the reactor coolant system boundary or disruption of the core or vessel internals to a degree that could impair the effectiveness of emergency core cooling.

The maximum positive reactivity insertion rates for the withdrawal of RCCAs and the dilution of the boric acid in the RCS are limited by the physical design characteristics of the RCCAs and of the CVCS. Technical Specifications on shutdown margin and on RCCA insertion limits and bank overlaps as functions of power provide additional assurance that the consequences of the postulated accidents are no more severe than those presented in the analyses of FSAR Chapter 15. Reactivity insertion rates, dilution, and withdrawal limits are also discussed in FSAR Section 4.3. The capability of the CVCS to avoid an inadvertent excessive rate of boron dilution is discussed in FSAR Chapter 15.

Assurance of core cooling capability following Condition IV accidents, such as rod ejections, steam line breaks, etc., is given by keeping the reactor coolant pressure boundary stresses within faulted condition limits as specified by applicable ASME codes. Structural deformations are checked also and limited to values that do not jeopardize the operation of necessary safety features.

- GDC-31, Fracture Prevention of Reactor Coolant Pressure Boundary, is described in FSAR Section 3.1.2.31.

  Close control is maintained over material selection and fabrication for the RCS to assure that the boundary behaves in a non-brittle manner. The RCS materials exposed to the coolant are corrosion resistant stainless steel or Inconel. The NIL ductility reference temperature of the RV structural steel is established by Charpy V-notch and drop weight tests, in accordance with 10 CFR 50, Appendix G.

The fabrication and quality control techniques used in the fabrication of the RCS are consistent with those used for the RV. The inspections of the RV, pressurizer, piping, pumps and SGs are governed by ASME Code requirements (Refer to FSAR Chapter 5).

Allowable pressure-temperature relationships for plant heatup and cooldown rates are calculated using methods derived from the ASME Code, Section III, Appendix G, "Protection Against Non-Ductile Failure." This approach specifies that allowed stress intensity factors for all vessel operating conditions may not exceed the referenced stress intensity factor (KIR) for the metal temperature at any time. Operating specifications include conservative margins for predicted changes in the material reference temperature due to irradiation.

FSAR Section 15.3.3 discusses the RCP Shaft Seizure (locked rotor) event. FSAR Section 15.3.4 discusses the RCP shaft break. Both events are classified as ANS Condition IV incidents (limiting faults).

FSAR Section 15.3.3 states in part that the accident postulated is an instantaneous seizure of a RCP rotor. Flow through the affected RC loop is rapidly reduced, leading to an initiation of a reactor trip on a low flow signal. One case has been analyzed: four loops in operation, one locked rotor.

The RCP shaft seizure transient is analyzed by two digital computer codes. The LOFTRAN code (WCAP-7907-P-A) is used to calculate the resulting loop and core flow transients following the pump seizure, the time of reactor trip based on the loop flow transients, the nuclear power following reactor trip, and to determine the peak pressure. The thermal behavior of the fuel located at the core hot spot is investigated using the FACTRAN Code (WCAP-7908-A, 1989), which uses the core flow and the nuclear power calculated by LOFTRAN. The FACTRAN Code includes a film boiling heat transfer coefficient.

FSAR Sections 15.3.3.2 and 15.0.3 provide initial plant conditions (reactor power, pressure, RCS temperature). FSAR Section 15.3.3.2 provides the sequence of events for this transient. FSAR Section 15.3.3.2 also provides assumptions relative to DNBR, film boiling coefficient, fuel clad gap coefficient, and zirconium steam reaction. FSAR Table 15.0-6 and FSAR Section 15.0.8 list or discuss plant systems and equipment, which are necessary to mitigate the effects of the accident. The results of these analyses for the locked rotor transient are summarized in FSAR Table 15.3-2.

FSAR Section 15.3.3.3 states the following conclusions for the locked rotor event:

1. Since the peak RCS pressure reached during any of the transients is less than that which would cause stresses to exceed the faulted condition stress limits, the integrity of the primary coolant system is not endangered.

2. Since the peak clad surface temperature calculated for the hot spot during the worst transient remains considerably less than 2,700°F, the core remains in place and intact with no loss of core cooling capacity.

FSAR Section 15.3.4 addresses the instantaneous failure of a RCP shaft, as discussed in FSAR Section 5.4. Flow through the affected RC loop is rapidly reduced, though the initial rate of reduction of coolant flow is greater for the RCP seizure (locked rotor) event. Reactor trip is initiated on a low flow signal in the affected loop.

FSAR Section 15.3.4.2 addresses the radiological consequences of the RCP shaft break accident. These consequences are no worse than those calculated for the locked rotor incident. With a failed shaft, the impeller could conceivably be free to spin in a reverse direction, as opposed to being fixed in position, as assumed in the locked rotor analysis. However, the net effect on core flow is negligible, resulting in only a slight decrease in the end point (steady state) core flow. For both the shaft break and locked rotor incidents, reactor trip occurs very early in the transient. In addition, the locked rotor analysis conservatively assumes that DNB occurs at the beginning of the transient.

Westinghouse NSALs -02-3 Rev. 01; -02-4 Rev. 0 and –02-05 Rev. 01 were reviewed for their impacts on the current licensing basis regarding these transients. The transients discussed in this section are not impacted by the issues raised in the NSALs.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.3.2.2 Technical Evaluation

The specific acceptance criteria for this event are as follows:

- The peak cladding temperature must remain below 2700°F and the maximum zirconium-water reaction must remain below 16 percent. Appropriate margin for malfunctions, such as stuck rods, were accounted for in the safety analysis assumptions. Demonstrating that these limits are met satisfies the requirements of GDC-27 and GDC-28.
- Pressures in the RCS and MSS are to be maintained less than that which would cause stresses to exceed the faulted condition stress limits for very low probability events such as locked rotor. Due to the short time before reactor trip the overpressurization of the MSS is bounded by the Turbine Trip/Loss of Load event. For the RCS system this limit is interpreted to be the minimum pressure at which emergency condition stress intensity limits are reached, 3200 psig, based on the ASME Boiler and Pressure Vessel Code. Demonstrating that this limit is met satisfies the requirements of GDC-28.
- The total percentage of rods-in-DNB should be less than that analyzed in the dose analysis. The specific limit for the SPU analysis is 7 percent.

The discussion below demonstrates that all applicable acceptance criteria were met for this event at MPS3 at SPU conditions.

2.8.5.3.2.2.1 Introduction

The event postulated is an instantaneous seizure of a RCP rotor or the sudden break of the shaft of the RCP (FSAR Sections 15.3.3 and 15.3.4). Flow through the affected reactor coolant loop (RCL) is rapidly reduced, leading to initiation of a reactor trip on a low RCL flow signal.

Following initiation of the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transfer to the shell-side of the steam generators is reduced, first because the reduced flow results in a decreased tube-side film coefficient, and then because the reactor coolant in the tubes cools down while the shell-side temperature increases (turbine steam flow is reduced to zero upon plant trip due to turbine trip on reactor trip). The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the PORVs, and opens the PSVs, in that sequence. The PORVs are designed for reliable operation and are expected to function properly during the event. However, for conservatism, their pressure-reducing effect, as well as the pressure-reducing effect of the spray, was not included in the analysis.

The consequences of a locked rotor (i.e., an instantaneous seizure of a pump shaft) are very similar to those of a pump shaft break. The initial rate of the reduction in coolant flow is slightly greater for the locked rotor event. However, with a broken shaft, the impeller could conceivably be free to spin in the reverse direction. The effect of reverse spinning is a reduced core flow when compared to the locked rotor scenario. The analysis considers only one scenario: it represents the most limiting combination of conditions for the locked rotor and pump shaft break events.

2.8.5.3.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

There were two locked rotor cases analyzed: one for peak RCS pressure and peak cladding temperature (PCT) concerns and a second to determine the percentage of rods-in-DNB. The case evaluating peak RCS pressure and PCT assumed one locked rotor and shaft break with all RCLs in operation. This case made assumptions designed to maximize the RCS pressure and cladding temperature transients. It was done using the Standard Thermal Design Procedure (STDP). Initial core power, reactor coolant temperature, and pressure were assumed to be at their maximum values consistent with full-power conditions, including allowances for calibration and instrument errors. This assumption resulted in a conservative calculation of the coolant insurge into the pressurizer, which in turn resulted in a maximum calculated peak RCS pressure.

A second case was run to confirm that the percentage of rods-in-DNB is less than that assumed in the radiological analysis. As in the peak RCS pressure/PCT case, one locked rotor and shaft break was assumed with all RCLs in operation. Initial core power was assumed to be at its nominal value consistent with steady-state, full-power operation. The reactor coolant system pressure and vessel average temperature were assumed to be at their nominal values. Minimum measured flow was also assumed. Uncertainties in initial conditions were accounted for in the DNBR limit value for the WRB-2M correlation as described in the RTDP.

A zero moderator temperature coefficient (MTC) and a conservatively large (absolute value) Doppler-only power coefficient were assumed in the analysis. The negative reactivity from control rod insertion/scram was based on 4.0 percent k/k trip reactivity from HFP.

The only safety system that provides mitigation for a Locked Rotor event is a reactor trip. The engineered safety systems (e.g., safety injection) are not required to function. Therefore, the limiting single failure assumed was the failure of one line of reactor trip protection. However, due to the redundancy designed into the protection system, this does not prevent or delay the reactor trip. As such, there is no single failure which yields more limiting analysis results.

Following the reactor trip, it was conservatively assumed as a consequential failure that a Loss of Offsite Power (LOOP) occurs due to the disturbance of the electrical grid. This results in a coastdown of the remaining reactor coolant pumps. However, this has little effect on the accident, as the reactor power is rapidly reduced as a result of the trip.

The RCP locked rotor/shaft break accident is classified by the ANS as a Condition IV event. An RCP locked rotor/shaft break results in a rapid reduction in forced RCL flow that increases the reactor coolant temperature and subsequently causes the fuel cladding temperature and RCS pressure to increase. The following items summarize the criteria associated with this event:

- Fuel cladding damage, including melting, due to increased reactor coolant temperatures must be prevented. This is precluded by demonstrating that the maximum cladding temperature at the core hot spot remains below 2700°F, and the zirconium-water reaction at the core hot spot is less than 16 percent by weight.
- Pressures in the RCS and MSS are to be maintained less than that which would cause stresses to exceed the faulted condition stress limits for very low probability events such as locked rotor. For the RCS, this limit is interpreted to be the minimum pressure at which emergency condition stress intensity limits are reached, 3200 psig, based on the ASME Boiler and Pressure Vessel Code.
- The total percentage of rods-in-DNB is less than that analyzed in the dose analysis. The specific limit for the SPU analysis is 7 percent.

2.8.5.3.2.2.3 Description of Analyses and Evaluations

The locked-rotor transient was analyzed with two primary computer codes. First, the RETRAN computer code (Reference 1) was used to calculate the loop and core flows during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE code (Reference 2) was then used to calculate the PCT using the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN.

These computer codes are different than those used for the current licensing basis analysis where the LOFTRAN (WCAP-7907-P-A) and FACTRAN (WCAP-7908-A, 1989) codes are used. RETRAN and VIPRE have been approved by the NRC for the analysis of Loss of Forced Reactor Coolant Flow (Reference 1 and 2). The applicability of the RETRAN and VIPRE codes to MPS3 for the SPU is discussed in Section 2.8.5.0.

For the peak RCS pressure analysis, the initial pressure was conservatively estimated to be 50 psi above the nominal pressure of 2250 psia, to allow for initial condition uncertainties in the pressurizer pressure measurement and control channels. This was done to obtain the highest possible rise in the coolant pressure during the transient. The pressure response reported in Table 2.8.5.3.2-2 is at the point in the RCS having the maximum pressure, i.e., in the lower plenum of the reactor vessel.

No credit was taken for the pressure-reducing effect of the pressurizer PORVs, pressurizer spray, steam dump or controlled feedwater flow after plant trip. Although these systems are expected to function and would result in a lower peak pressure, an additional degree of conservatism was provided by not including their effect. The PSV model included a +3 percent valve tolerance above the nominal setpoint of 2500 psia.

The film boiling coefficient was calculated in the VIPRE code (Reference 2) using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties were evaluated at film temperature. The program calculated the film coefficient at every time-step based upon the actual heat transfer conditions at the time. The nuclear power, system pressure, bulk density, and RCS flow rate as a function of time were based on the RETRAN results.

The magnitude and time dependence of the heat transfer coefficient between the fuel and cladding (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between the pellet and cladding. Based on investigations on the effect of the gap coefficient upon the maximum cladding temperature during the transient, the gap coefficient was assumed to increase from a steady-state value consistent with the initial fuel temperature to approximately 10,000 Btu/hr-ft^2-°F at the initiation of the transient. Therefore, the large amount of energy stored in the fuel because of the small initial value was released to the cladding at the initiation of the transient.

The zirconium-steam reaction can become significant above 1800°F (cladding temperature). The Baker-Just parabolic rate equation was used to define the rate of zirconium-steam reaction. The effect of the zirconium-steam reaction was included in the calculation of the PCT temperature transient.

Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the RCP locked rotor/shaft break analysis. As stated in Section 2.8.5.3.1.2.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.3.2.2.4 Results

With respect to the peak RCS pressure, PCT, and zirconium-steam reaction, the analysis demonstrated that all applicable acceptance criteria were met. The calculated sequence of events is presented in Table 2.8.5.3.2-1 for the locked rotor/shaft break event. The results of the calculations (peak pressure, PCT, and zirconium-steam reaction) are summarized in Table 2.8.5.3.2-2. The transient results for the peak pressure/PCT case are provided in Figure 2.8.5-1 through 2.8.5-3.

The analysis performed for the SPU demonstrated that, for the locked rotor event, the PCT calculated for the hot spot during the worst transient remained considerably less than 2700°F, and the amount of zirconium-water reaction was small. Under such conditions, the core would remain in place and intact with no loss of core cooling capability.

The secondary side pressure remained approximately constant at the initial value of 991 psia until the reactor trip. Following the trip, the pressure slowly rises due to the loss of steam flow to the turbine, eventually reaching the steam system safety valve setpoint. Therefore, the maximum secondary side pressure does not exceed the safety valve setpoint.

The analysis also confirmed that the peak RCS pressure reached during the transient was less than 3200 psig, and thereby, the integrity of the primary coolant system was demonstrated. The total number of rods-in-DNB was less than 7 percent. The low RCS flow reactor trip function provided mitigation for the locked rotor/shaft break transient such that the above criteria were satisfied. Furthermore, the results and conclusions of this analysis are confirmed on a cycle-specific basis as part of the normal reload process.

2.8.5.3.2.3 Conclusion

DNC has reviewed the analyses of the RCP rotor seizure and RCP shaft break events and concludes that the analyses have adequately accounted for plant operation at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and adequate core cooling will be provided. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -27, -28, and -31 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the sudden decrease in core coolant flow events.

2.8.5.3.2.4 References

1. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999.

2. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999.

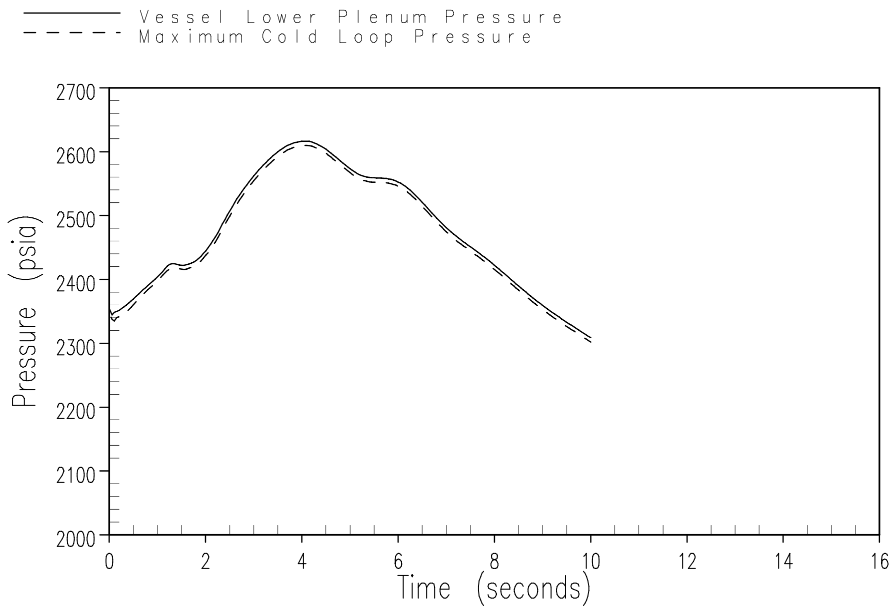
Table 2.8.5.3.2-1
Time Sequence of Events – Single RCP Locked Rotor/Shaft Break

Event	Time (sec)
Rotor on One Pump Locked or the Shaft Breaks	0.0
Low Flow Reactor Trip Setpoint Reached	0.1
Rods Begin to Drop	1.1
Remaining Pumps Lose Power and Begin to Coast Down	1.1
Peak Cladding Temperature Occurs	3.7
Maximum RCS Pressure Occurs	4.1

Table 2.8.5.3.2-2
Results for Single RCP Locked Rotor/Shaft Break and Comparison to Previous Results

Criteria	SPU Analysis	Previous Analysis*	Limit
Peak Cladding Temperature at Core Hot Spot, °F	1718.	1969.	2700.
Maximum Zirconium-Water Reaction at Core Hot Spot,%	0.22	0.5	16.0
Maximum RCS Pressure, psia	2616.6	2652.	3214.7
Total number of rods-in-DNB,%	<7	<6 (old limit)	<7
*It should be noted that the previous analysis of record used an earlier version of the fuel performance computer program PAD (3.0 vs. 4.0) which resulted in more limiting results.			

Figure 2.8.5-1
Single RCP Locked Rotor/Shaft Break
RCS Pressure and Loop Flows vs. Time



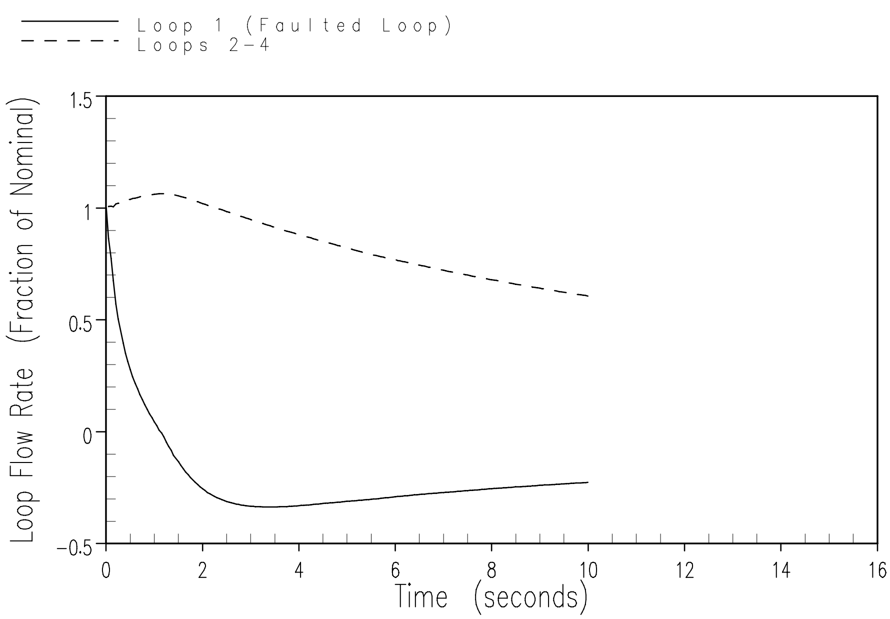


Figure 2.8.5-2
Single RCP Locked Rotor/Shaft Break
Nuclear Power and Total Core Inlet Flow vs. Time

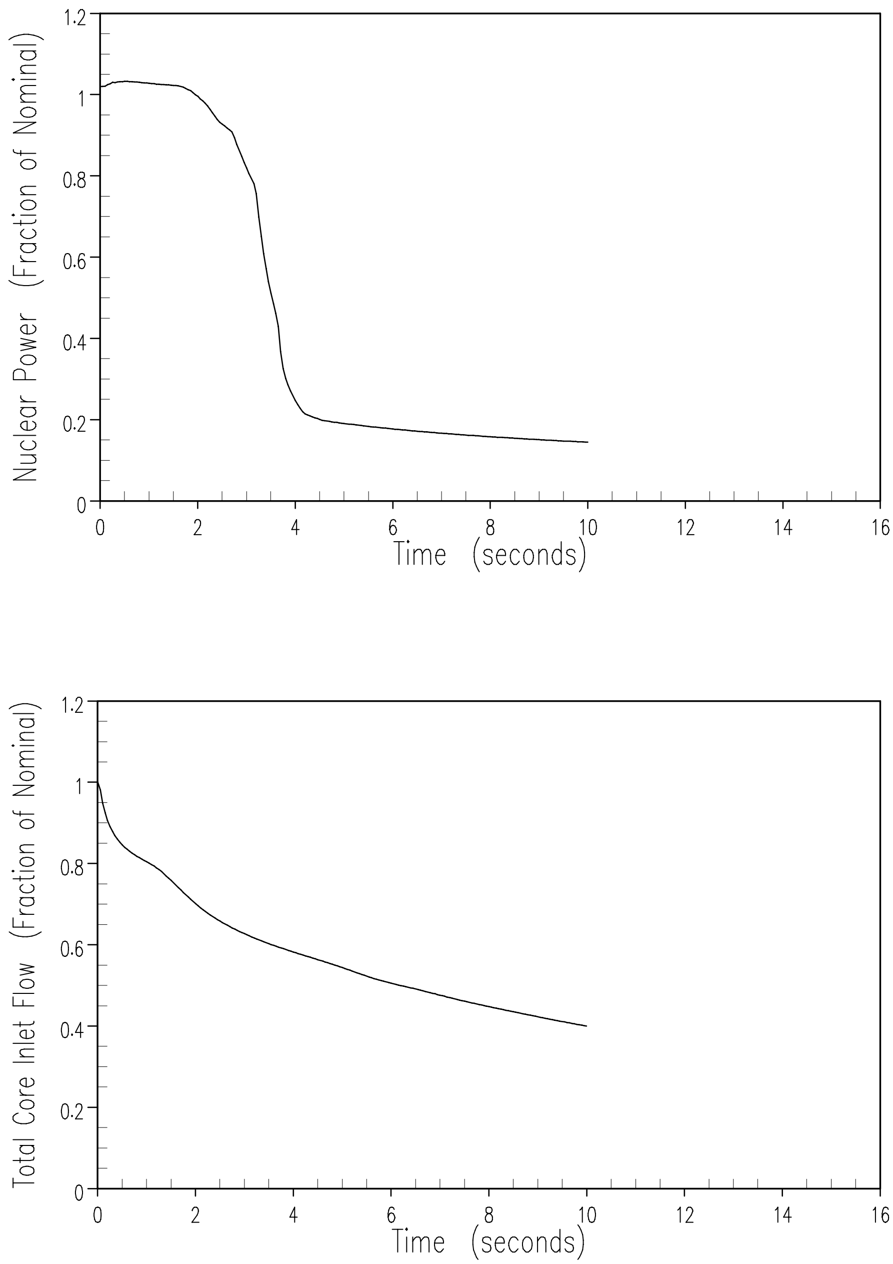
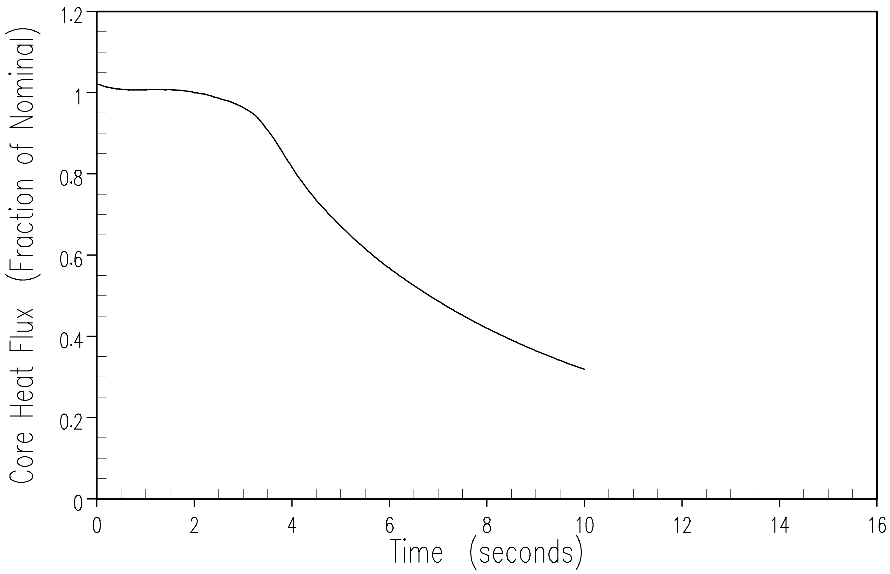
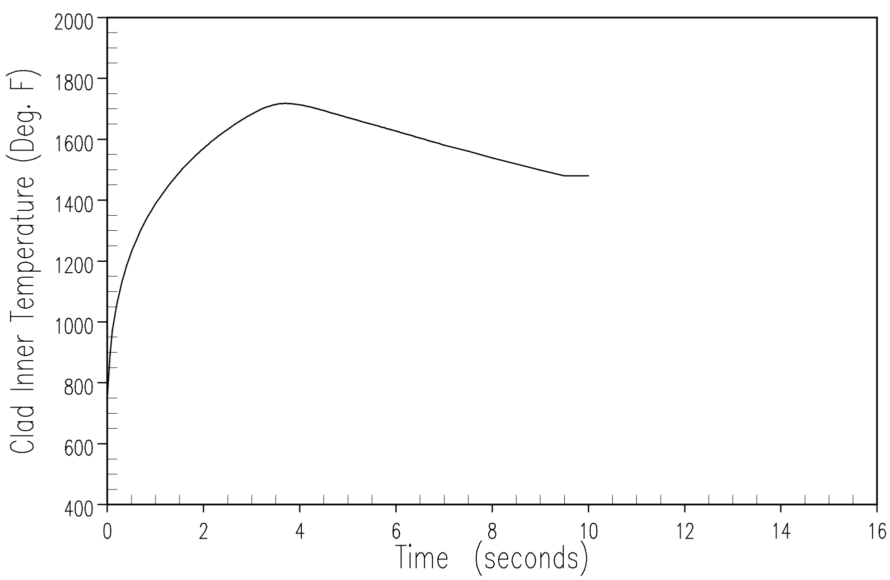


Figure 2.8.5-3
Single RCP Locked Rotor/Shaft Break
Core Average Heat Flux and Cladding Inside Temperature vs. Time





2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Rod Cluster Control Assembly Withdrawal from a Subcritical or Low Power Startup Condition

2.8.5.4.1.1 Regulatory Evaluation

An uncontrolled rod cluster control assembly (RCCA) withdrawal from subcritical or low-power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion.

The DNC review covered:

- The description of the causes of the transient and the transient itself
- The initial conditions
- The values of reactor parameters used in the analysis
- The analytical methods and computer codes used
- The results of the transient analyses

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including anticipated operational occurrences (AOOs)
- GDC-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs
- GDC-25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems

Specific review criteria are contained in SRP Section 15.4.1, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 15.4.1, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3’s design relative to:

- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.10.

The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant clean up system, and are consistent with plant design bases.

2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

   Note that the term “fuel damage” as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

   FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protection systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-20, Protection System Functions, is described in FSAR Section 3.1.2.20

  A fully automatic protection system, with appropriate redundant channels, is provided to cope with transients where insufficient time is available for manual corrective action. The design basis for all protection systems is IEEE Standard 279-1971 and IEEE Standard 379-1972. The reactor protection system automatically initiates a reactor trip when any variable exceeds the normal operating range. Setpoints are designed to provide an envelope of safe operating conditions with adequate margin for uncertainties to ensure that fuel design limits are not exceeded.

  Reactor trip is initiated by removing power to the rod drive mechanisms of all of the full length rod cluster control assemblies. This causes the rods to insert by gravity, which rapidly reduces reactor power output. The response and adequacy of the protection system have been verified by analysis of expected transients.

  The ESF actuation system automatically initiates emergency core cooling, and other safeguards functions, by sensing accident conditions using redundant analog channels measuring diverse variables. Manual actuation of safeguards equipment may be performed where ample time is available for operator action. The ESF actuation system automatically trips the reactor on manual or automatic Safety Injection Signal (SIS) generation.

- GDC-25, Protection System Requirements for Reactivity Control Malfunctions, is described in FSAR Section 3.1.2.25.

  The protection system is designed to limit reactivity transients so that fuel design limits are not exceeded. Reactor shutdown by full length rod insertion is completely independent of the normal control function, since the trip breakers interrupt power to the rod mechanisms regardless of existing control signals. Thus, in the postulated accidental withdrawal (assumed to be initiated by a control malfunction), flux, temperature, pressure, level and flow signals would be generated independently. Any of these signals (trip demands) would operate the breakers to trip the reactor.

  FSAR Chapter 15 discusses analyses of the effects of possible malfunctions. These analyses show that for postulated dilution during refueling, startup, or manual or automatic operation at power, the operator has ample time to determine the cause of dilution, terminate the source of dilution, and initiate boration before the shutdown margin is lost. The analyses show that acceptable fuel damage limits are not exceeded even in the event of a single malfunction of either system.

FSAR Section 15.4.1.1 states that the uncontrolled RCCA bank withdrawal from a subcritical or low power startup condition is an ANS Condition II event. This transient could be caused by a malfunction of the reactor control or rod control systems.

The transient is analyzed utilizing three computer codes. First, the average core nuclear calculation is performed using spatial neutron kinetics methods TWINKLE (WCAP-7979-A and WCAP-8028), to determine the average power generation with time including the various total core feedback effects, i.e., Doppler reactivity and moderator reactivity. Second, the average heat flux and temperature transients are determined by performing a fuel rod transient heat transfer calculation in FACTRAN (WCAP-7908-A). Third, the average heat flux is next used in THINC (FSAR Section 4.4) for transient DNBR calculation.

FSAR Section 15.4.1.3 concludes that, in the event of an uncontrolled RCCA withdrawal from the subcritical condition, the core and the RCS are not adversely affected, since the combination of thermal power and the coolant temperature result in a DNBR greater than the limit value. The DNBR design basis is described in FSAR Section 4.4. Applicable acceptance criteria have been met.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.4.1.2 Technical Evaluation

The specific acceptance criteria applied for this event were as follows:

- The DNBR should remain above the 95/95 DNBR limit at all times during the transient. Demonstrating that the DNBR limit is met satisfies the requirements of GDC-10.
- Per GDC-20, the protection system should be designed to automatically initiate the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs, and to sense accident conditions and initiate the operation

of safety-related systems and components. For this event, protection is provided via the high neutron flux reactor trip.

- GDC-25 requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods. Demonstrating that the fuel design limits (i.e., DNBR) are met satisfies the requirements of GDC-25.

The discussion below demonstrates that all applicable acceptance criteria were met for this event at MPS3 at SPU conditions.

2.8.5.4.1.2.1 Introduction

An uncontrolled RCCA withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core by withdrawal of RCCAs resulting in a power excursion. While the probability of a transient of this type is extremely low, such a transient could be caused by a faulty operator action or by a malfunction of the reactor control rod drive system. This could occur with the reactor either subcritical or at power. The “at power” occurrence is discussed in Section 2.8.5.4.2 of this report. The uncontrolled RCCA withdrawal from a subcritical condition is classified as an ANS Condition II event of moderate frequency.

Reactivity is added at a prescribed and controlled rate in bringing the reactor from a shutdown condition to a low power level during startup by RCCA withdrawal or by reducing the core boron concentration. RCCA motion can cause much faster changes in reactivity than can result from changing boron concentration.

The rods are physically prevented from withdrawing in other than their respective banks. Power supplied to the rod banks is controlled such that no more than two banks can be withdrawn at any time. The rod drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable speed rod travel. The maximum reactivity insertion rate is analyzed in the detailed plant analysis assuming the simultaneous withdrawal of the combination of the two rod banks with the maximum combined worth at maximum speed.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the initial power increase results from a fast negative fuel temperature feedback (Doppler effect) and is of prime importance during a startup transient since it limits the power to an acceptable level prior to protection system action. After the initial power increase, the nuclear power is momentarily reduced and then, if the incident is not terminated by a reactor trip, the nuclear power increases again, but at a much slower rate.

Should a continuous RCCA withdrawal be initiated, the transient is terminated by one of the following automatic protective functions:

1. Source range neutron flux reactor trip – actuated when either of two independent source range channels indicates a flux level above a pre-selected, manually adjustable setpoint. This trip function may be manually bypassed when either of the intermediate range neutron flux channels indicates a flux (P-6 permissive) above the source range cutoff power level. It is

automatically reinstated when both intermediate channels indicate a flux level below the source range cutoff power level.

2. Intermediate range neutron flux reactor trip – actuated when either of two independent intermediate range channels indicates a flux level above a pre-selected, manually adjustable setpoint. This trip function may be manually bypassed when two of the four power range channels are reading above the P-10 permissive and is automatically reinstated when three of the four channels indicate a power level below this value.

3. Power range neutron flux reactor trip (low setting) – actuated when two out of the four power range channels indicate a power level above approximately 25 percent. This trip function may be manually bypassed when two of the four power range channels indicate a power level above the P-10 permissive. This trip function is automatically reinstated when three of the four channels indicate a power level below this value.

4. Power range neutron flux reactor trip (high setting) – actuated when two out of the four power range channels indicate a power level above a preset setpoint. This trip function is always active.

5. Power range neutron flux high positive rate reactor trip – actuated when the positive rate of change of neutron flux on two out of the four nuclear power range channels indicates a rate above the preset setpoint.

This analysis credits the power range neutron flux trip (low setting) to initiate the reactor trip.

2.8.5.4.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The accident analysis uses the Standard Thermal Design Procedure (STDP) methodology since the conditions resulting from the transient are outside the range of applicability of the Revised Thermal Design Procedure (RTDP) methodology (Reference 4). To obtain conservative results for the analysis of the uncontrolled RCCA bank withdrawal from subcritical event, the following input parameters and initial conditions are modeled:

1. The magnitude of the nuclear power peak reached during the initial part of the transient, for any given reactivity insertion rate, is strongly dependent on the Doppler-only power defect. Therefore, a conservatively low absolute value is used (900 pcm) to maximize the nuclear power transient.

2. A most-positive moderator temperature coefficient (+5 pcm/°F) is used since this yields the maximum rate of power increase. The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and moderator is much longer than the nuclear flux response time constant.

However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient.

3. The analysis assumes the reactor to be at hot zero power conditions with a nominal no-load temperature of 557°F. This assumption is more conservative than that of a lower initial system temperature (i.e., shutdown conditions). The higher initial system temperature yields a larger fuel-to-moderator heat transfer coefficient, a larger specific heat of the moderator and fuel, and a less-negative (smaller absolute magnitude) Doppler defect. The less-negative Doppler defect reduces the Doppler feedback effect, thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel specific heat and larger heat transfer coefficient yields a larger peak heat flux.

4. The analysis assumes the initial effective multiplication factor ($K_{eff)}$ to be 1.0 since it maximizes the peak neutron flux and results in the most severe nuclear power transient.

5. Reactor trip is assumed on power range high neutron flux (low setting). A conservative combination of instrumentation error, setpoint error, delay for trip signal actuation, and delay for control rod assembly release is modeled. The analysis assumes a 10 percent uncertainty in the power range flux trip setpoint (low setting), raising it from the nominal value, 25 percent, to 35 percent. A delay time of 0.5 second is assumed for trip signal actuation and control rod assembly release. No credit is taken for the source range or intermediate range protection. During the transient, the rise in nuclear power is so rapid that the effect of errors in the trip setpoint on the actual time at which the rods release is negligible. In addition, the total reactor trip reactivity is based on the assumption that the highest worth rod cluster control assembly is stuck in its fully withdrawn position.

6. The maximum positive reactivity insertion rate assumed (75 pcm/sec) is greater than that for the simultaneous withdrawal of the two sequential control banks having the greatest combined worth at the maximum rod withdrawal speed.

7. The DNB analysis assumes the most-limiting axial and radial power shapes possible during the fuel cycle associated with having the two highest combined worth banks in their highest worth position.

8. The analysis assumes the initial power level to be below the power level expected for zero-power (just-critical) condition (10^{-9} fraction of nominal power). The combination of highest reactivity insertion rate and low initial power produces the highest peak heat flux.

9. The analysis assumes two of the four RCPs to be in operation. This is conservative with respect to the DNB transient.

10. The use of the STDP methodology stipulates that the RCS flow rates be based on a fraction of the thermal design flow for two operating RCPs. Since the event is analyzed from hot zero

power, the steady-state non-RTDP uncertainties are not considered in defining the initial conditions.

The Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from Subcritical event is considered an ANS Condition II event, a fault of moderate frequency, and is analyzed to show that the core and reactor coolant system are not adversely affected by the event. This is demonstrated by showing that the DNB design basis is not violated and subsequently that there is little likelihood of core damage. It must also be shown that the peak hot spot fuel centerline temperature remains within the acceptable limit (4800°F), although for this event, the heat-up is relatively non-limiting.

2.8.5.4.1.2.3 Description of Analyses and Evaluations

The analysis of the uncontrolled RCCA bank withdrawal from subcritical conditions is performed in three stages. First, a spatial neutron kinetics computer code, TWINKLE (Reference 1), is used to calculate the core average nuclear power transient, including the various core feedback effects, i.e., Doppler and moderator reactivity. Next, the FACTRAN computer code (Reference 2) uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the core average heat flux and hot spot fuel temperature transients. Finally, the core average heat flux calculated by FACTRAN is used in the VIPRE computer code (Reference 3) for transient DNBR calculations.

This computer code used for the transient DNBR calculations is different than that used for the current licensing basis analysis where the THINC code is used. VIPRE has been approved by the NRC for the analysis of uncontrolled RCCA bank withdrawal from subcritical transients (Reference 3).

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the RCCA bank withdrawal from subcritical analysis. As stated in Section 2.8.5.4.1.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.4.1.2.4 Results

The analysis shows that all applicable acceptance criteria are met. The minimum DNBR never goes below the limit value and the peak fuel centerline temperature is 2631°F. The peak temperature is well below the minimum temperature where fuel melting would be expected (4800°F).

Figure 2.8.5.4.1-1 shows the nuclear power and core average heat flux transients and Figure 2.8.5.4.1-2 shows the inner clad and fuel temperature transients at the hot spot.

The time sequence of events is presented in Table 2.8.5.4.1-1. Numerical results of the SPU DNB analysis are shown in Table 2.8.5.4.1-2.

The power range high neutron flux (low setting) trip function was shown to provide adequate protection for this event. In the event of an uncontrolled RCCA withdrawal event from subcritical conditions, the core and the RCS are not adversely affected since the combination of thermal power and coolant temperature results in a minimum DNBR greater than the safety analysis limit value. Furthermore, since the maximum fuel temperatures predicted to occur during this event are much less than those required for fuel melting to occur, no fuel damage is predicted as a result of this transient. Clad damage is also precluded.

2.8.5.4.1.3 Conclusion

DNC has reviewed the analyses of the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition and concludes that the analyses have adequately accounted for the changes in core design necessary for operation of the plant at the SPU power level. DNC also concludes that the analyses were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition.

2.8.5.4.1.4 References

1. WCAP-7979-P-A, (Proprietary) and WCAP-8028-A, (Nonproprietary), TWINKLE, a Multi-dimensional Neutron Kinetics Computer Code, Barry, R. F., and Risher, D. H., January 1975.

2. WCAP-7908-A, FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO2 Fuel Rod, Hargrove, H. G., December 1989.

3. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999.

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

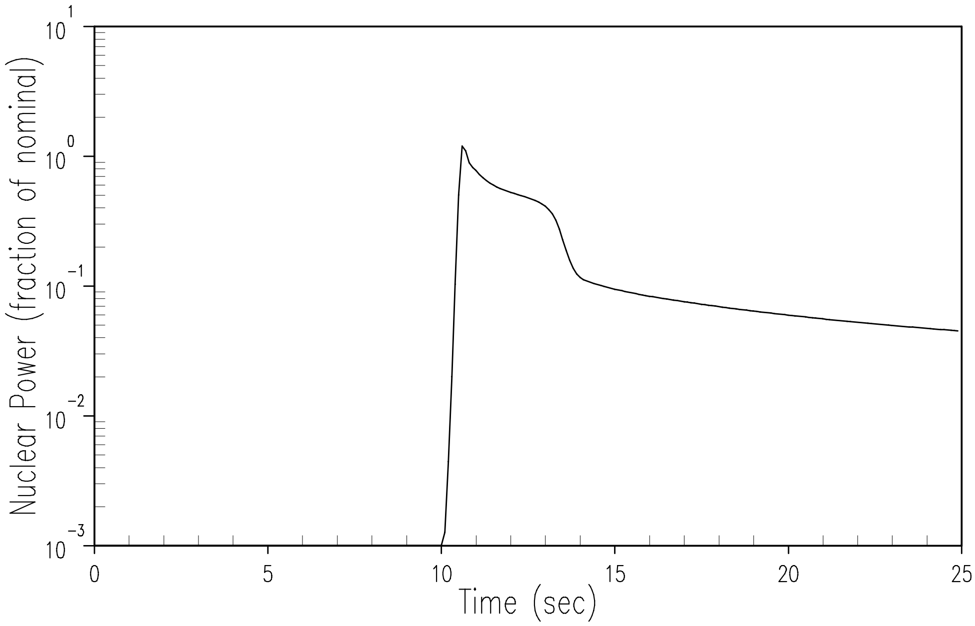
Table 2.8.5.4.1-1
Time Sequence of Events – Uncontrolled RCCA Withdrawal from a Subcritical Condition

Event	Time (sec)
Initiation of uncontrolled rod withdrawal from 10^{-9} of nominal power	0.0
Power range high-neutron flux (low setting of 0.35) setpoint reached	10.43
Peak nuclear power occurs	10.58
Rods begin to fall into the core	10.93
Peak heat flux (avg. channel) occurs/Minimum DNBR occurs	12.80
Peak average clad temperature occurs	13.20
Peak average fuel temperature occurs	13.40
Peak fuel centerline temperature occurs	14.20

Table 2.8.5.4.1-2
Uncontrolled RCCA Withdrawal from a Subcritical Condition Results

DNBR	SPU Results (typical/thimble)	Limit (typical/thimble)
Minimum DNBR below first mixing vane grid	1.413/1.306	1.30/1.30
Minimum DNBR above first mixing vane grid	1.392/1.411	1.17/1.17

Figure 2.8.5.4.1-1
Rod Withdrawal from Subcritical:
Nuclear Power and Core Average Heat Flux versus Time



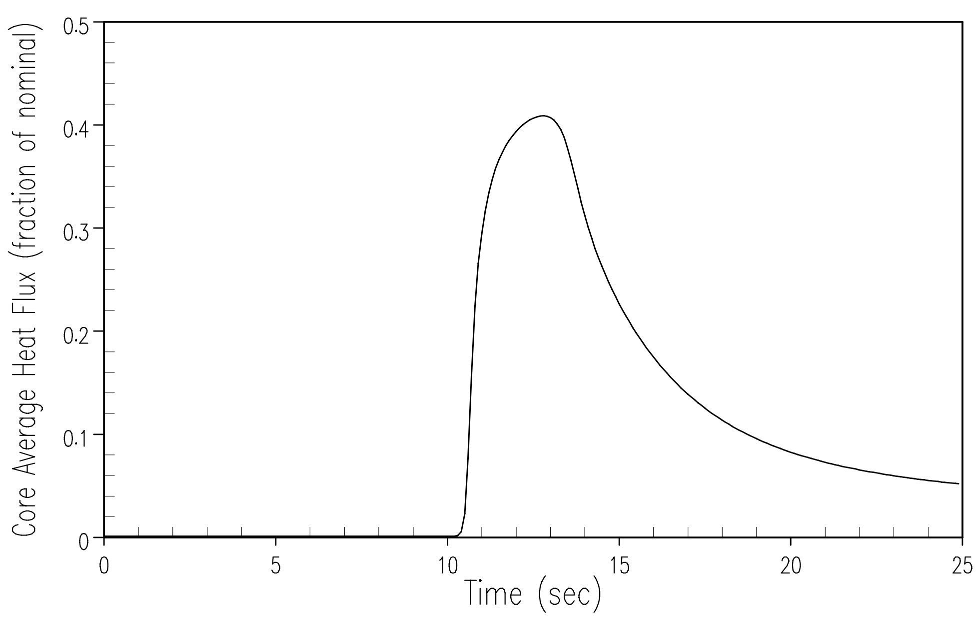
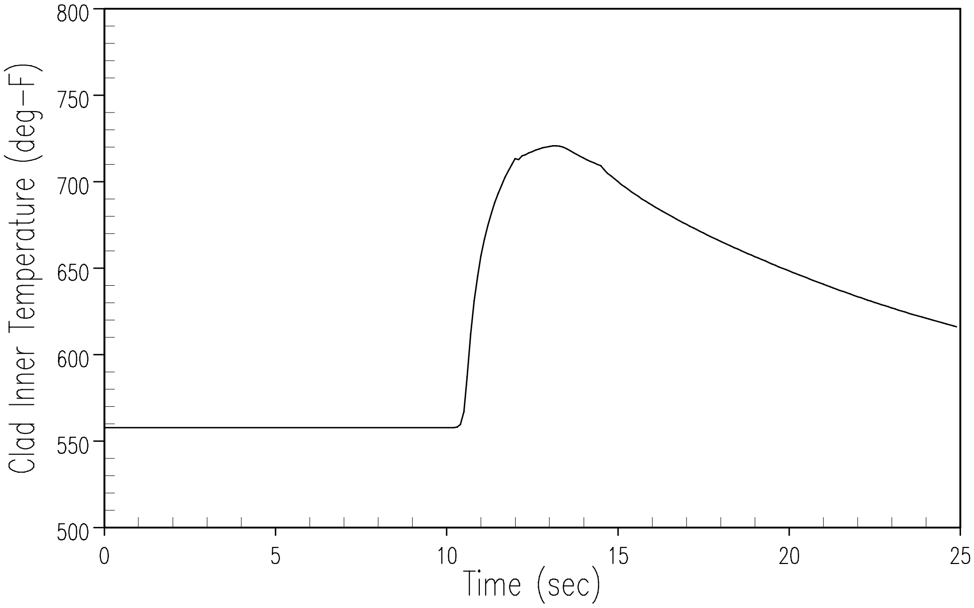
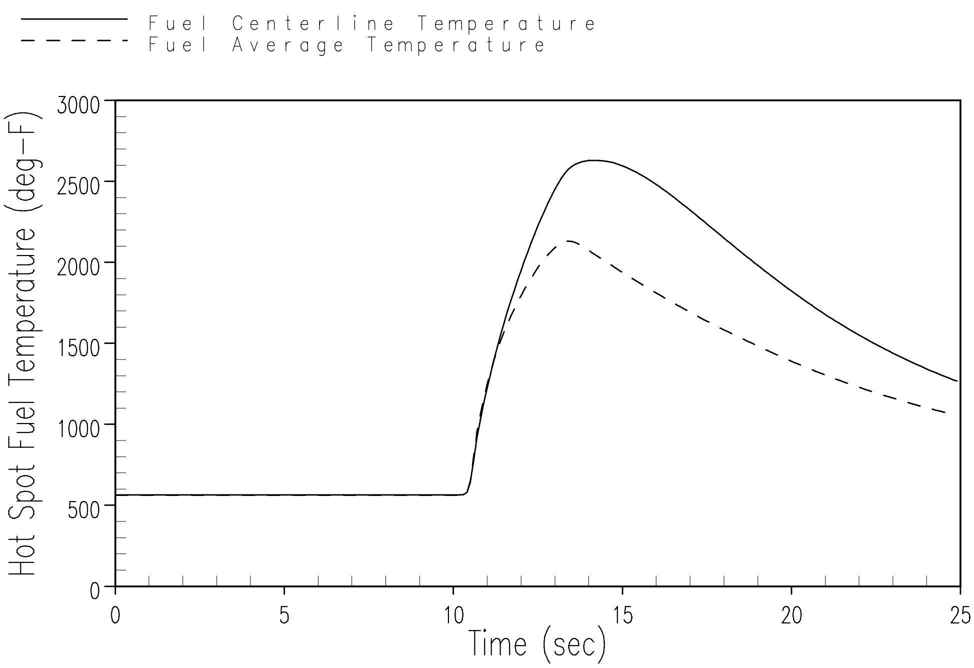


Figure 2.8.5.4.1-2
Rod Withdrawal from Subcritical:
Clad Inner and Hot Spot Fuel Temperatures versus Time





2.8.5.4.2 Uncontrolled Rod Cluster Control Assembly Withdrawal at Power

2.8.5.4.2.1 Regulatory Evaluation

An uncontrolled RCCA withdrawal at power can be caused by a faulty operator action or a malfunction of the rod control system. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion.

The DNC review covered:

- The description of the causes of the anticipated operational occurrence (AOO) and the description of the event itself
- The initial conditions
- The values of reactor parameters used in the analyses
- The analytical methods and computer codes used
- The results of the associated analyses

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including AOOs
- GDC-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs
- GDC-25, insofar as it requires that the protection system be designed to ensure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems

Specific review criteria are contained in SRP Section 15.4.2, and other guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 15.4.2, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to:

- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

  1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant clean up system, and are consistent with plant design bases.

  2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

  3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

  Note that the term “fuel damage” as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

  FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-20, Protection System Functions, is described in FSAR Section 3.1.2.20

  A fully automatic protection system, with appropriate redundant channels, is provided to cope with transients where insufficient time is available for manual corrective action. The design basis for all protection systems is IEEE Standard 279-1971 and IEEE Standard 379-1972. The reactor protection system automatically initiates a reactor trip when any variable exceeds the normal operating range. Setpoints are designed to provide an envelope of safe operating conditions with adequate margin for uncertainties to ensure that fuel design limits are not exceeded.

  Reactor trip is initiated by removing power to the rod drive mechanisms of all of the full length rod cluster control assemblies. This causes the rods to insert by gravity, which rapidly reduces reactor power output. The response and adequacy of the protection system have been verified by analysis of expected transients.

  The ESF actuation system automatically initiates emergency core cooling, and other safeguards functions, by sensing accident conditions using redundant analog channels measuring diverse variables. Manual actuation of safeguards equipment may be performed where ample time is available for operator action. The ESF actuation system automatically trips the reactor on manual or automatic Safety Injection Signal (SIS) generation.

- GDC-25, Protections System Requirements for Reactivity Control Malfunctions, is described in FSAR Section 3.1.2.25.

  The protection system is designed to limit reactivity transients so that fuel design limits are not exceeded. Reactor shutdown by full length rod insertion is completely independent of the normal control function, since the trip breakers interrupt power to the rod mechanisms regardless of existing control signals. Thus, in the postulated accidental withdrawal (assumed to be initiated by a control malfunction), flux, temperature, pressure, level and flow signals would be generated independently. Any of these signals (trip demands) would operate the breakers to trip the reactor.

  FSAR Chapter 15 discusses analyses of the effects of possible malfunctions. These analyses show that for postulated dilution during refueling, startup or manual or automatic operation at power, the operator has ample time to determine the cause of dilution, terminate the source of dilution, and initiate boration before the shutdown margin is lost. The analyses show that acceptable fuel damage limits are not exceeded even in the event of a single malfunction of either system.

FSAR Section 15.4.2.1 states that uncontrolled RCCA bank withdrawal at power results in an increase in the core heat flux. Since the heat extraction from the steam generator lags behind the core power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise could eventually result in DNB. Therefore, in order to avert damage to the fuel clad, the reactor protection system is designed to terminate any such transient before the DNBR falls below the safety analysis limit value. This event is classified as an ANS Condition II incident.

FSAR Section 15.4.2.2 states that the transient is analyzed with the LOFTRAN Code (WCAP-7907-P-A). It computes pertinent plant variables including temperatures, pressures, and power level.

FSAR Section 15.4.2.3 concludes that the high neutron flux and overtemperature ΔT trip channels provide adequate protection over the entire range of possible reactivity insertion rates; i.e., the minimum value of DNBR is always larger than the safety analysis limit value. The analysis did assume that the high pressurizer water level reactor trip would prevent pressurizer filling and that the positive flux rate and high pressurizer pressure functions can provide a timely reactor trip to preclude RCS overpressurization in instances where the high neutron flux or OTΔT trips occur too late to provide the necessary protection.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.4.2.2 Technical Evaluation

2.8.5.4.2.2.1 Introduction

An uncontrolled RCCA withdrawal at power that causes an increase in core heat flux can result from faulty operator action or a malfunction in the rod control system. Immediately following the initiation of the accident, the steam generator heat removal rate lags behind the core power generation rate until the steam generator pressure reaches the setpoint of the steam generator relief or safety valves. This imbalance between heat removal and heat generation rate causes the reactor coolant temperature to rise. Unless terminated, the power mismatch and resultant coolant temperature rise could eventually result in a violation of the DNBR limit and/or fuel centerline melt. Therefore, to avoid core damage; the reactor protection system is designed to automatically terminate any such transient before the DNBR falls below the limit value, or the fuel rod linear heat generation rate (kW/ft) limit is exceeded.

The automatic features of the reactor protection system that prevent core damage in an RCCA bank withdrawal incident at power include the following:

- Power range high neutron flux instrumentation actuates a reactor trip on neutron flux if two-out-of-four channels exceed an overpower setpoint.
- Reactor trip actuates if any two-out-of-four channels exceed the high positive neutron flux rate setpoint.
- Reactor trip actuates if any two-out-of-four T channels exceed an overtemperature T setpoint. This setpoint is automatically varied with axial power distribution, coolant average temperature, and coolant average pressure to protect against violating the DNBR limit.
- Reactor trip actuates if any two-out-of-four T channels exceed an overpower T setpoint.
- A high-pressurizer pressure reactor trip actuates if any two-out-of-four pressure channels exceed a fixed setpoint.
- A high-pressurizer water level reactor trip actuates if any two-out-of-three level channels exceed a fixed setpoint.
- Main steam safety valves (MSSVs) can open for this event and provide an additional heat sink.

2.8.5.4.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

A number of cases were analyzed assuming a range of reactivity insertion rates for both minimum and maximum reactivity feedback conditions at various power levels. The cases presented below are representative for this event.

For an uncontrolled RCCA bank withdrawal at power accident, the analysis modeled the following conservative assumptions:

- This accident was analyzed with the Revised Thermal Design Procedure (RTDP) (Reference 1). Initial reactor power, RCS pressure, and RCS temperature were assumed to be at their nominal SPU values. Minimum measured flow was modeled. Uncertainties in initial conditions were included in the DNBR limit as described in the RTDP.
- For reactivity coefficients, two cases were analyzed.
- Minimum reactivity feedback: A moderator temperature coefficient (MTC) of +5 pcm/°F is used for power levels less than 70 percent rated thermal power (RTP) consistent with the Technical Specifications. A moderator temperature coefficient of 0 pcm/°F is used for the

100 percent power cases. Also, a least-negative Doppler-only power coefficient is assumed. These formed the basis for the beginning-of-life (BOL) minimum reactivity feedback assumption.

- Maximum reactivity feedback: A conservatively large, positive moderator density coefficient of 0.5 k/g/cc (corresponding to a large negative MTC) and a most-negative Doppler-only power coefficient formed the basis for the end-of-life (EOL) maximum reactivity feedback assumption.

• The reactor trip on high neutron flux was assumed to be actuated at a conservative value of 116.5 percent of nominal full power. This decrease in the Safety Analysis Limit (SAL) from the value of 118 percent assumed in the current analysis was made to obtain acceptable results for the 10 percent initial power case with a minimal loss of reserved DNB margin. As stated in Section 2.4.1.2.3.1, there is sufficient margin between the reduced SAL and the existing nominal trip setpoint in the high nuclear flux trip to account for the required uncertainties.

• The ΔT trip setpoints were revised to reflect the thermal-hydraulic conditions at the higher SPU reactor power level. The ΔT trips included all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation were assumed at their maximum values. The ΔT trip setpoints are discussed in Section 2.4.1.2.3.1.

• The RCCA trip insertion characteristic was based on the assumption that the highest-worth RCCA was stuck in its fully withdrawn position.

• A range of reactivity insertion rates was examined. The maximum-positive reactivity insertion rate was greater than that corresponding to the simultaneous withdrawal of the two control rod banks having the maximum combined worth at a conservative speed of 45 inches/minute (72 steps/minute).

• To be conservative with respect to DNB, the pressurizer sprays and relief valves were assumed operational since they limit the reactor coolant pressure increase.

• Power levels of 10, 60, and 100 percent of the NSSS power of 3666 MWt were considered.

Based on its frequency of occurrence, the uncontrolled RCCA bank withdrawal at-power accident is considered a Condition II event as defined by the ANS. The following items summarize the main acceptance criteria associated with this event:

• The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.

• Pressure in the RCS and main steam system (MSS) should be maintained below 110 percent of the design pressures.

The protection features presented in Licensing Report Section 2.8.5.4.2.2.1 provide mitigation of the uncontrolled RCCA bank withdrawal at-power transient such that the above criteria are satisfied.

Also, a conservative generic evaluation which is applicable to MPS3 has shown that the positive flux rate and high pressurizer pressure functions provide a timely reactor trip that precludes RCS overpressurization in instances where the power range high neutron flux – high setting or the

OTΔT trips occur too late to provide the necessary protection. This evaluation confirms that the design RCS pressure limit is met. The generic method has been reviewed and approved by the NRC in Amendments 167 and 168 for the Diablo Canyon Nuclear Plant, Units 1 and 2, dated April 22, 2004. This evaluation method was also used in the current FSAR analysis.

2.8.5.4.2.2.3 Description of Analyses and Evaluations

The purpose of this analysis was to demonstrate the manner in which the protection functions described above actuate for various combinations of reactivity insertion rates and initial conditions. Insertion rate and initial conditions determined which trip function actuated first.

The uncontrolled rod withdrawal at-power event was analyzed with the RETRAN computer code (Reference 2). The program simulated the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and main steam safety valves (MSSVs). The program computed pertinent plant variables including temperatures, pressures, power level, and DNBR (based on a conservative calculational model: partial derivative approximation of the DNB core limit lines).

Although RETRAN has the capability of calculating the transient value of the DNBR, a detailed DNB analysis was performed for the limiting cases with the thermal and hydraulic computer code VIPRE (Reference 3).

These computer codes are different from the current licensing basis analysis where only the LOFTRAN code is used. RETRAN and VIPRE have been approved by the NRC for the analysis of uncontrolled RCCA withdrawal at power transients (Reference 2 and 3, respectively).

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the RCCA withdrawal at power analysis. As stated in Section 2.8.5.4.2.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.4.2.2.4 Results

Figures 2.8.5.4.2-1 through 2.8.5.4.2-3 show the transient response for a rapid uncontrolled RCCA bank withdrawal incident (100 pcm/sec) starting from 100 percent power with minimum feedback. Reactor trip on high neutron flux occurred shortly after the start of the accident. Because of the rapid reactor trip, small changes in T_{avg} and pressure resulted in the safety analysis margin to the DNBR limit being maintained.

The transient response for a slow uncontrolled RCCA bank withdrawal (1 pcm/sec) from 100 percent power with minimum feedback is shown in Figures 2.8.5.4.2-4 through 2.8.5.4.2-6. Reactor trip on overtemperature T occurred after a longer period of time, and the rise in temperature was consequently larger than for a rapid RCCA bank withdrawal. Again, the minimum DNBR was greater than the safety analysis limit value.

Figure 2.8.5.4.2-7 shows the minimum DNBR as a function of reactivity insertion rate from 100 percent power for both minimum and maximum reactivity feedback conditions. It can be seen that the high neutron flux and overtemperature T reactor trip functions provided DNB protection over the range of reactivity insertion rates. The minimum DNBR was never less than the safety analysis limit value.

Figures 2.8.5.4.2-8 and 2.8.5.4.2-9 show the minimum DNBR as a function of reactivity insertion rate for RCCA bank withdrawal incidents starting at 60 and 10 percent power, respectively. The results were similar to the 100 percent power case; however, as the initial power level decreased, the range over which the overtemperature T trip is effective was increased. The safety analysis DNBR limit was not met for all 10 percent power cases; a detailed DNB analysis using VIPRE showed a DNBR penalty of 3.2 percent. Therefore, in order to meet the RCCA bank withdrawal at power DNB design basis, 3.2 percent DNBR margin is reserved to offset the DNBR penalty as shown in Table 2.8.3-5.

A calculated sequence of events for two cases is shown in Table 2.8.5.4.2-1. With the reactor tripped, the plant eventually returned to a stable condition. The plant could subsequently be cooled down further by following normal plant shutdown procedures. Numerical results of the SPU analysis are shown in Table 2.8.5.4.2-2.

The high neutron flux and overtemperature T reactor trip functions provided adequate protection over the entire range of possible reactivity insertion rates. The results show that the DNB design basis is met and the peak kW/ft is less than the limit. The peak pressures in the RCS and MSS do not exceed 110 percent of their respective design pressures.

Therefore, the results of the analysis showed that an uncontrolled RCCA withdrawal at-power does not adversely affect the core, the RCS, or the MSS.

2.8.5.4.2.3 Conclusion

DNC has reviewed the analyses of the uncontrolled control rod assembly withdrawal at power event and concludes that the analyses have adequately accounted for the changes in core design required for operation of the plant at the SPU power level. DNC also concludes that the analyses were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -10, -20, and -25 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the uncontrolled control rod assembly withdrawal at power.

2.8.5.4.2.4 References

1. WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, April 1989.

2. WCAP-14882-P-A (Proprietary), WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, April and May 1999 respectively.

3. WCAP-14565-P-A (Proprietary), WCAP-15306-NP-A (Non-Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, October 1999.

Table 2.8.5.4.2-1
Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power

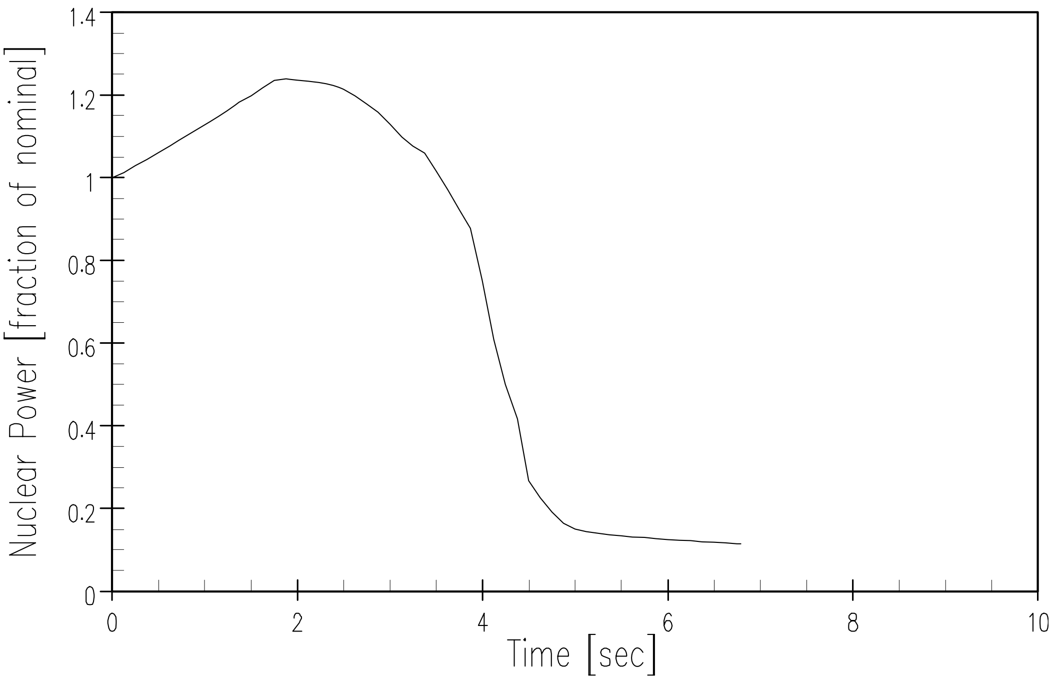
Case	**Event**	**Time (sec)**
100% Power, Minimum Feedback, Rapid RCCA Withdrawal (100 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	0.00
	Power Range High Neutron Flux – High Setpoint Reached	1.29
	Rods Begin to Fall	1.79
	Minimum DNBR Occurs	2.63
100% Power, Minimum Feedback, Slow RCCA Withdrawal (1 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	0.00
	Overtemperature T Setpoint Reached	93.63
	Rods Begin to Fall	95.13
	Minimum DNBR Occurs	95.75

Table 2.8.5.4.2-2
Uncontrolled RCCA Bank Withdrawal at Power – Limiting results

	Limiting value	Safety Analysis Limit	Case
Minimum DNBR	1.55*	1.6	10% power, minimum feedback 12 pcm/sec reactivity insertion rate
Peak Core Heat Flux (fon)	1.161	1.18	100% power, maximum feedback 34 pcm/sec reactivity insertion rate
Peak Secondary System Pressure (psia)	1294.6	1318.5	10% power, minimum feedback 15 pcm/sec reactivity insertion rate

* This corresponds to a 3.2% DNBR penalty ((1.55/1.60) -1= -0.03125, or ~ 3.2% penalty). In order to meet the DNB design basis 3.2% DNBR margin is reserved to offset the DNBR penalty as shown in Table 2.8.3-5.

Figure 2.8.5.4.2-1
Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 100 pcm/sec
Nuclear Power and Core Heat Flux vs. Time



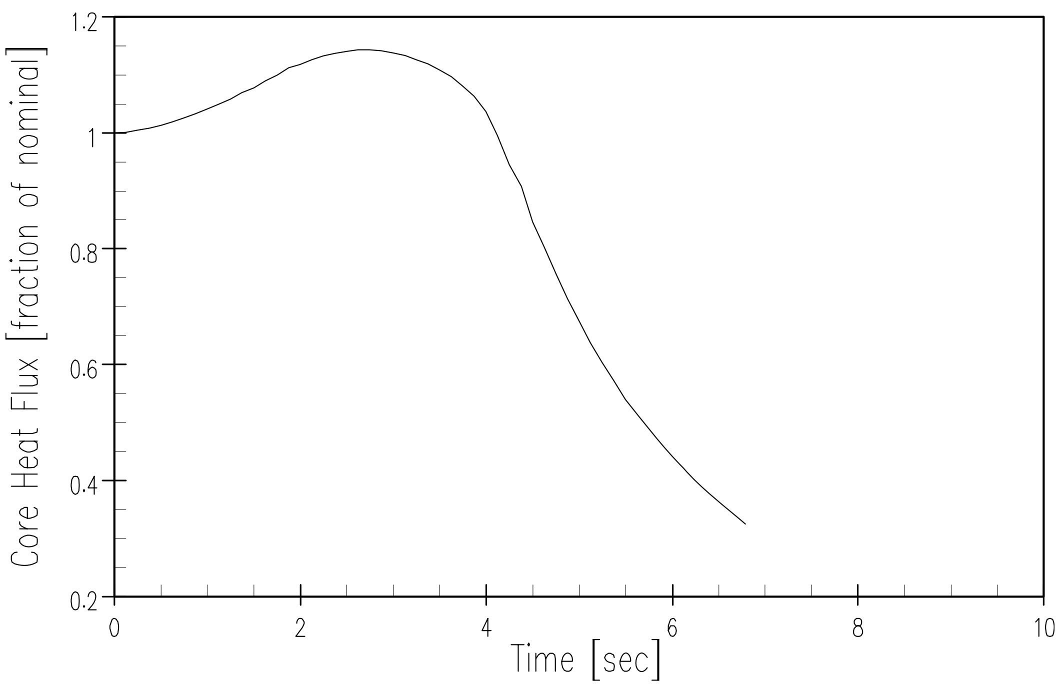


Figure 2.8.5.4.2-2
Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 100 pcm/sec
Pressurizer Pressure and Water Volume vs. Time

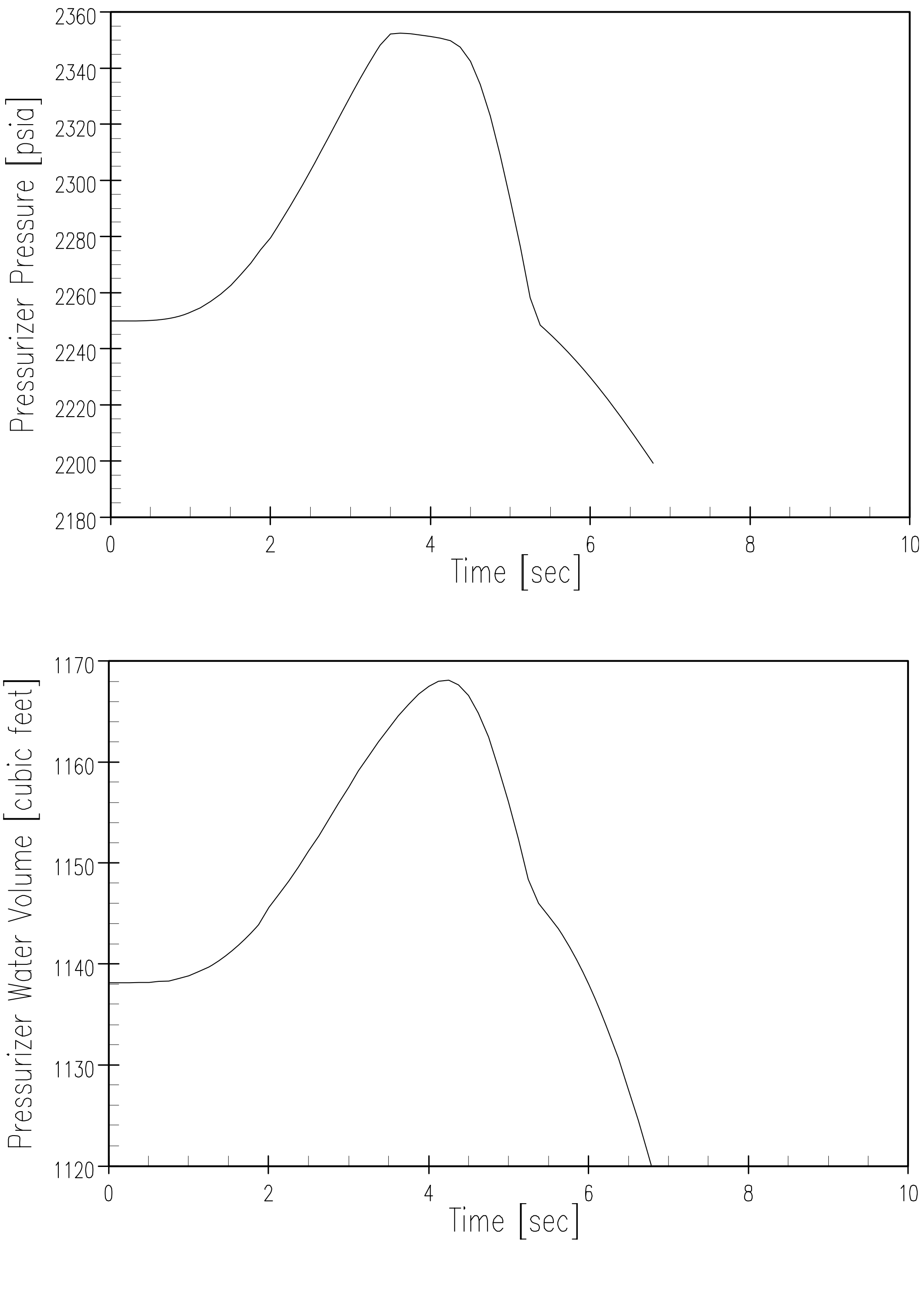
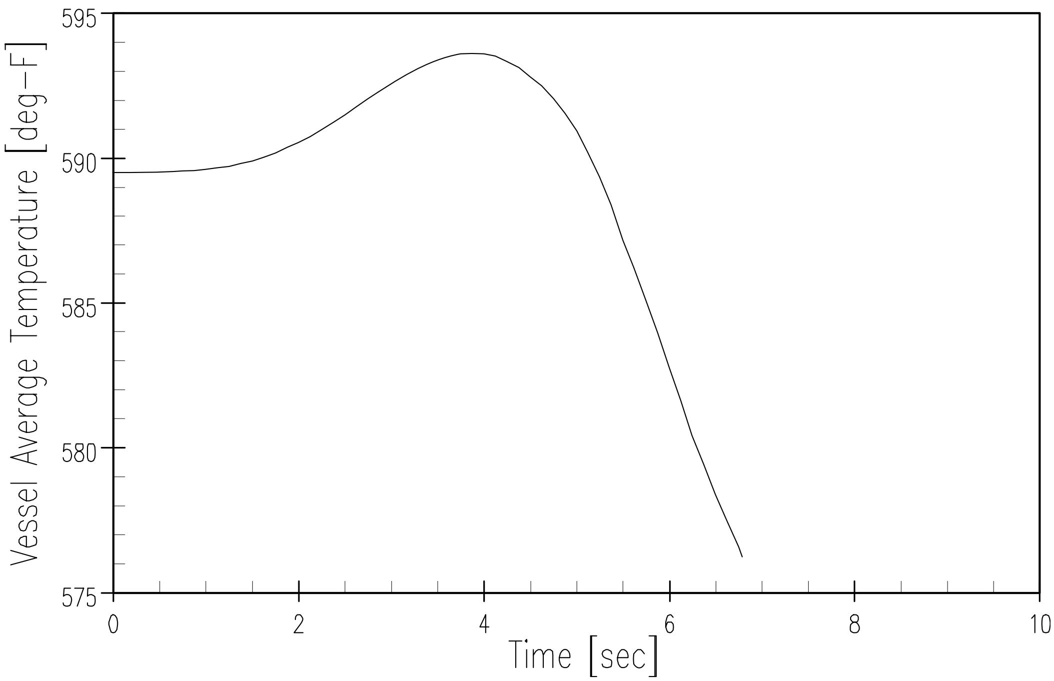


Figure 2.8.5.4.2-3
Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 100 pcm/sec
Vessel Average Temperature and DNBR vs. Time



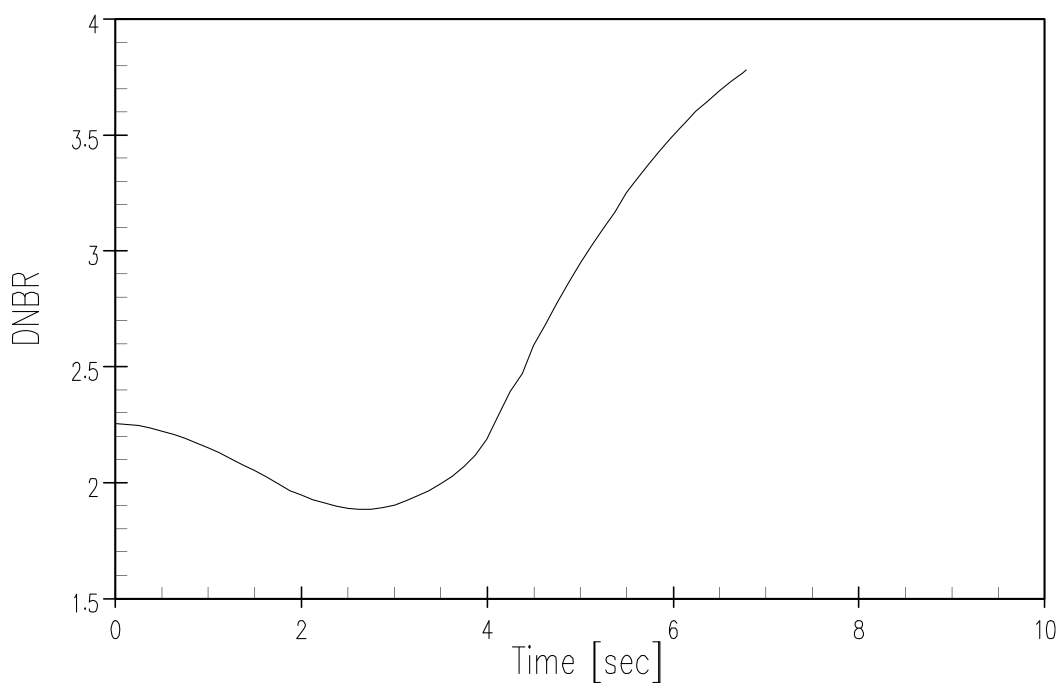
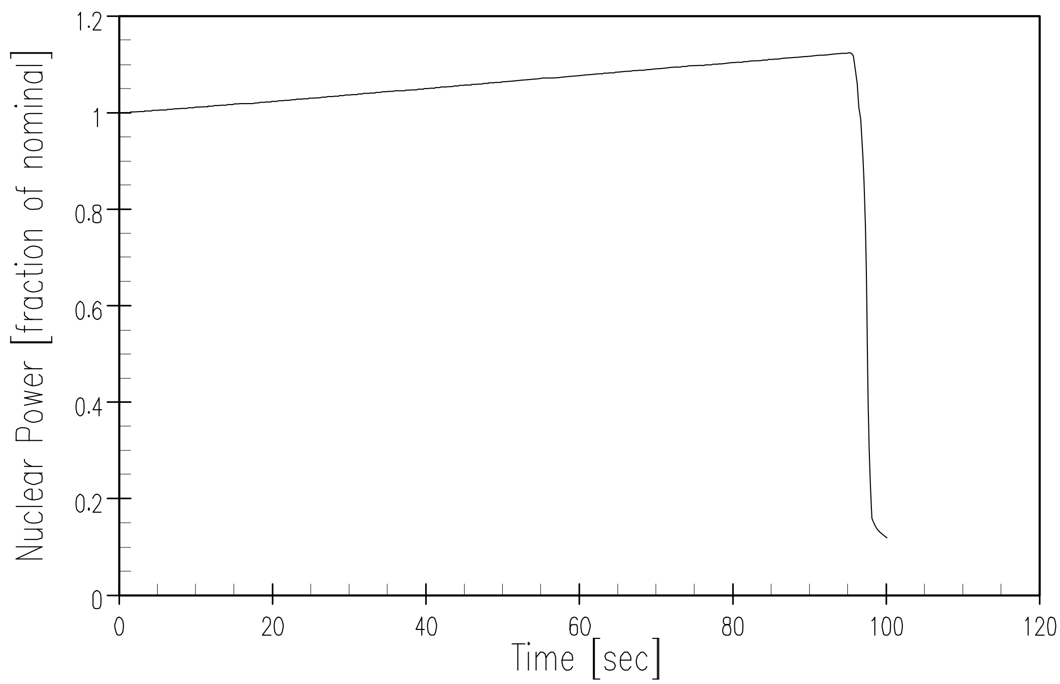


Figure 2.8.5.4.2-4
Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 1 pcm/sec
Nuclear Power and Core Heat Flux vs. Time



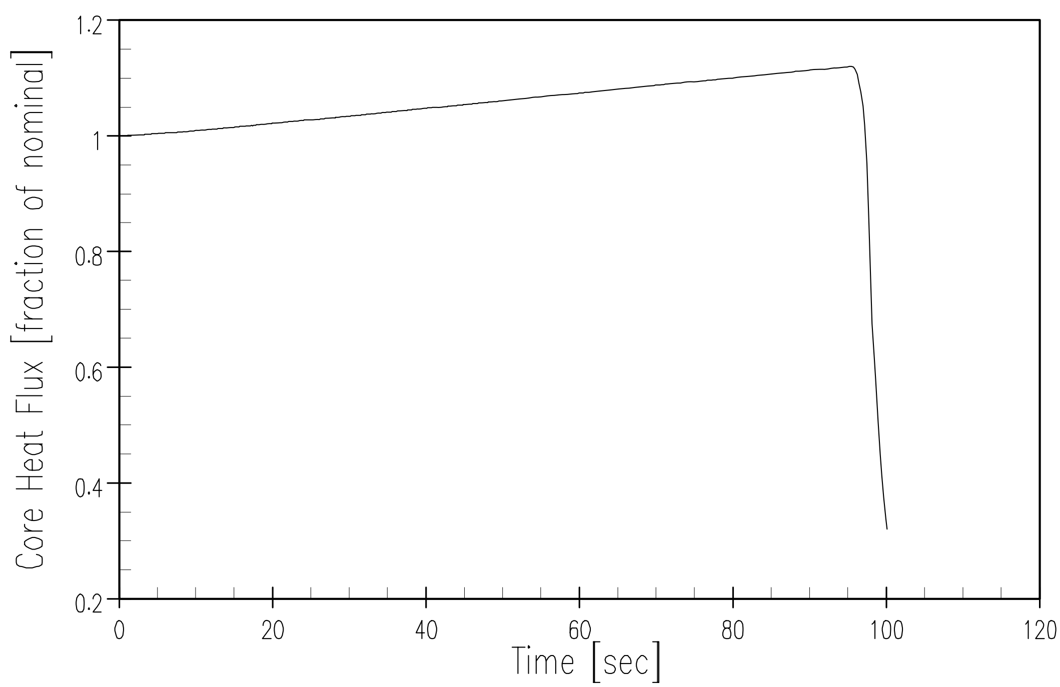
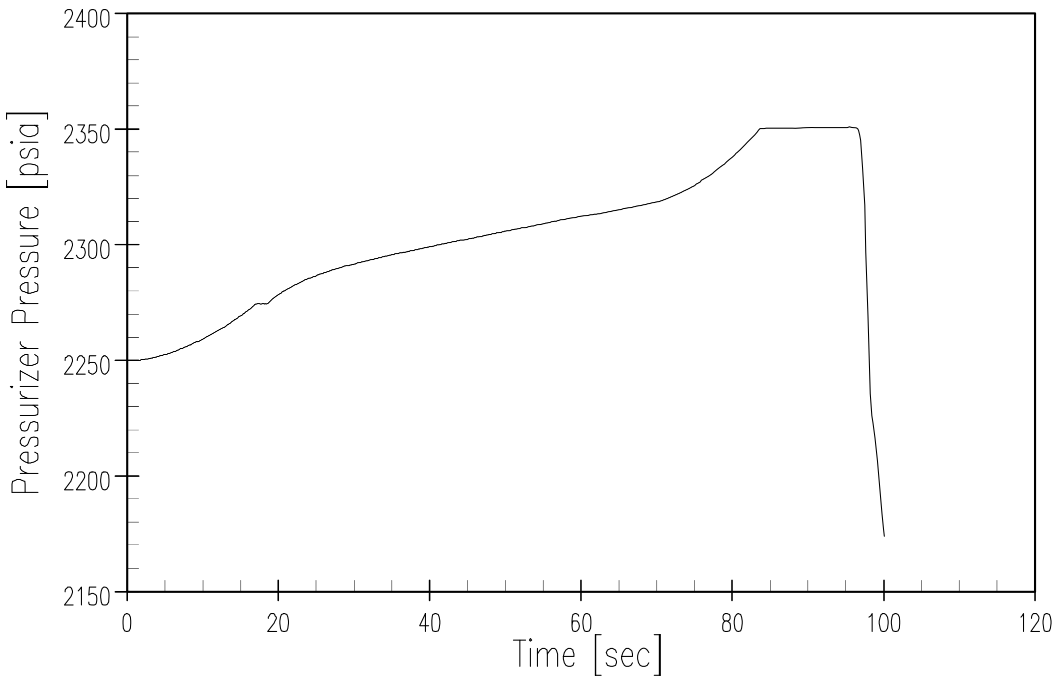


Figure 2.8.5.4.2-5
Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 1 pcm/sec
Pressurizer Pressure and Water Volume vs. Time



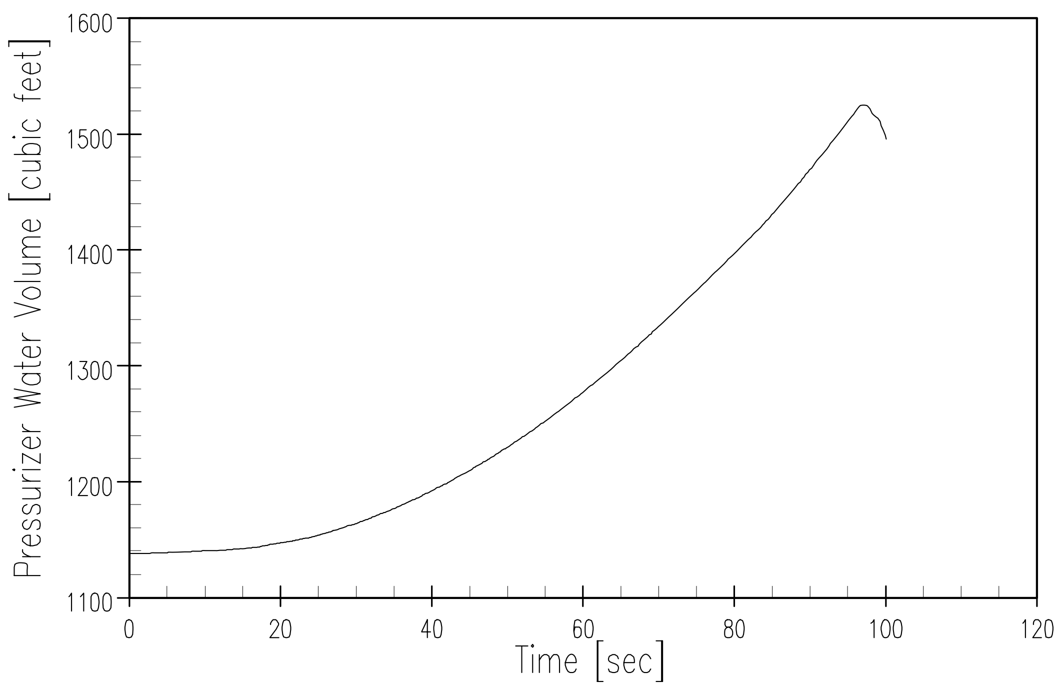


Figure 2.8.5.4.2-6
Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 1 pcm/sec
Vessel Average Temperature and DNBR vs. Time

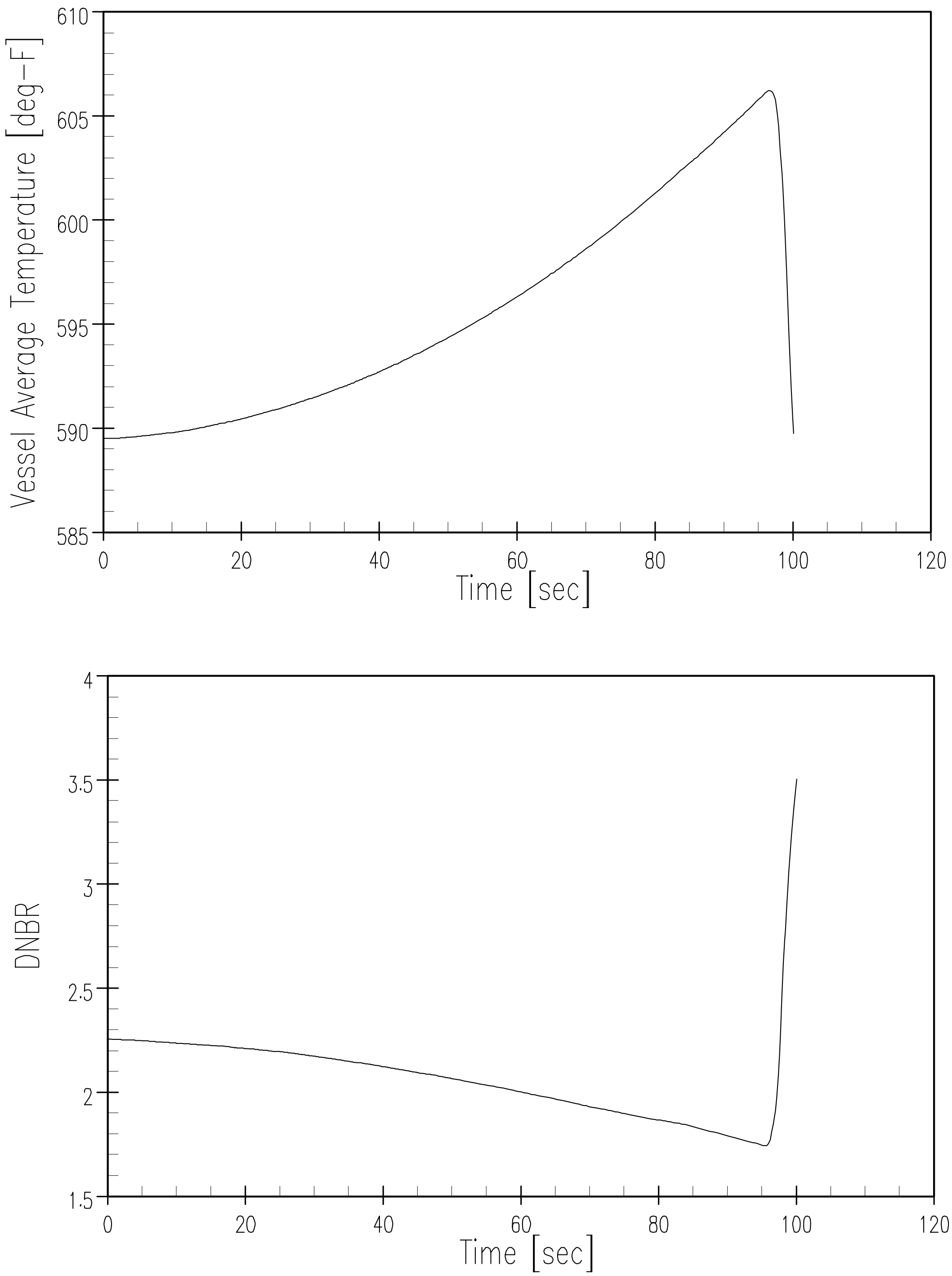


Figure 2.8.5.4.2-7
Rod Withdrawal at Power
100% Power
Minimum DNBR vs. Reactivity Insertion Rate

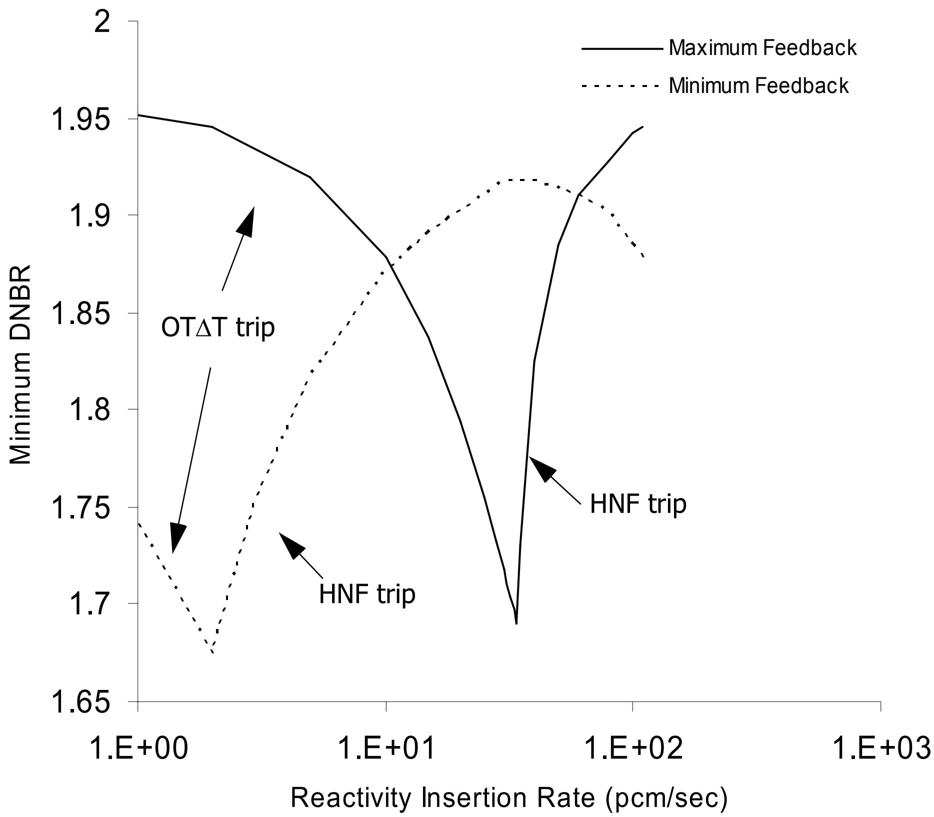


Figure 2.8.5.4.2-8
Rod Withdrawal at Power
60% Power
Minimum DNBR vs. Reactivity Insertion Rate

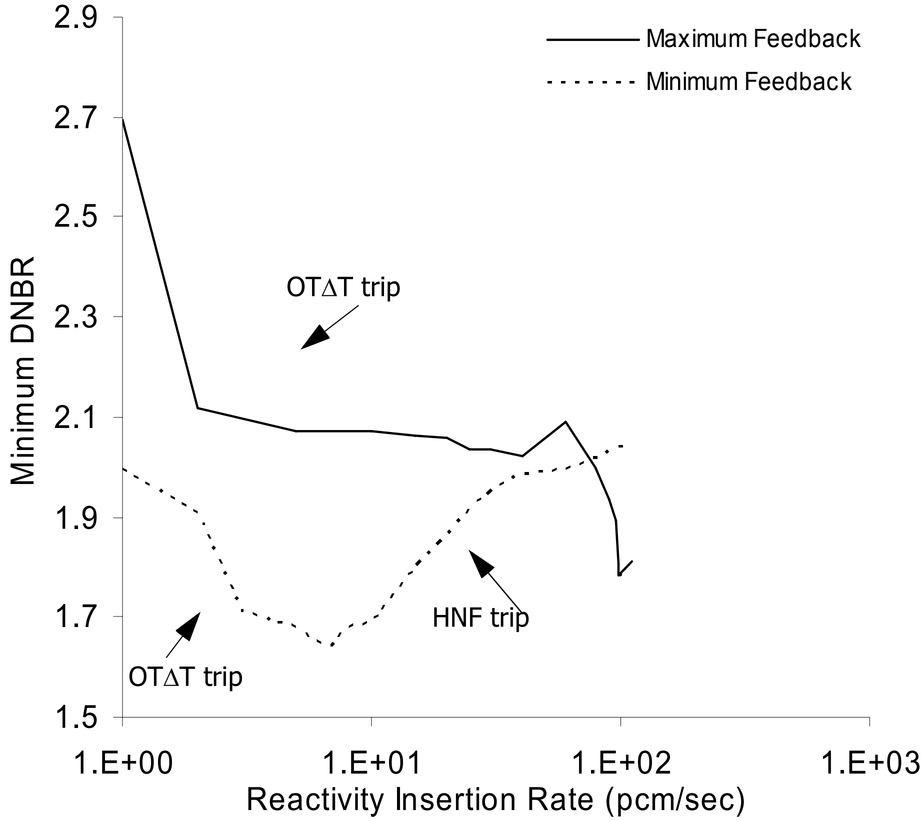
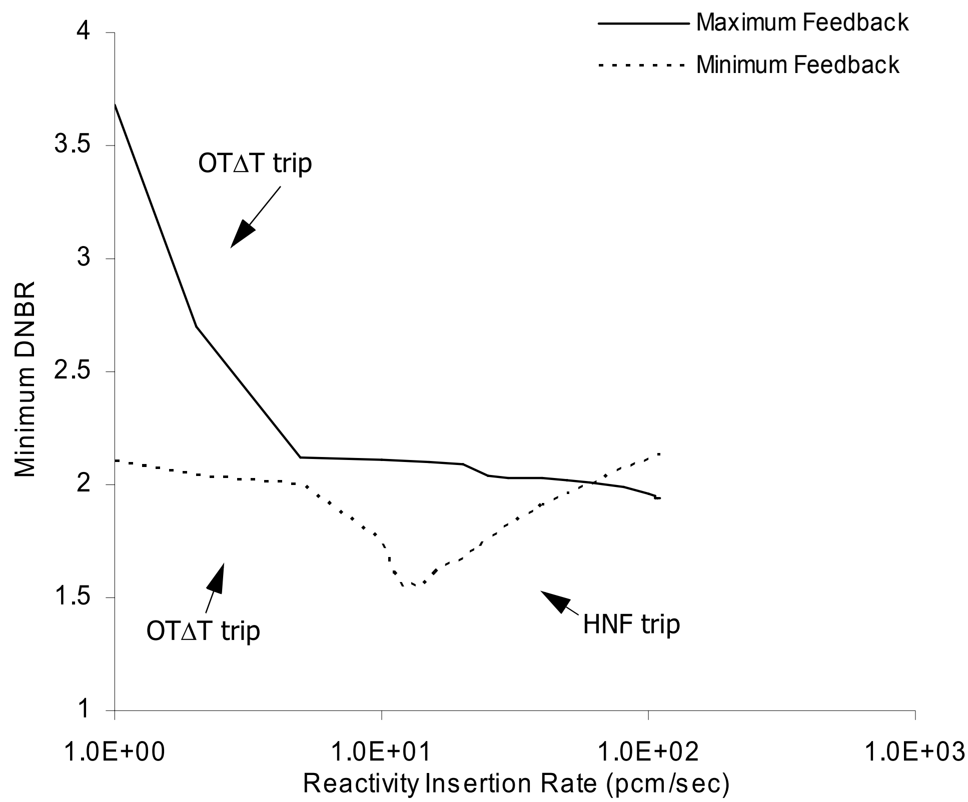


Figure 2.8.5.4.2-9
Rod Withdrawal at Power
10% Power
Minimum DNBR vs. Reactivity Insertion Rate



2.8.5.4.3 Rod Cluster Control Assembly Misalignment

2.8.5.4.3.1 Regulatory Evaluation

The DNC review covered the types of rod cluster control assembly misoperations that are assumed to occur, including those caused by a system malfunction or operator error. The review covered:

- The descriptions of rod position, flux, pressure, and temperature indication systems, and those actions initiated by these systems (e.g., turbine runback, rod withdrawal prohibit, rod block) that can mitigate the effects or prevent the occurrence of various misoperations
- The sequence of events
- The analytical model used for analyses
- The important inputs to the calculations
- The results of the analyses

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences (AOOs)
- GDC-20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to initiate automatically operation of systems and components important to safety under accident conditions
- GDC-25, insofar as it requires that the protection system be designed to ensure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems

Specific review criteria are contained in SRP Section 15.4.3, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 15.4.3, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to:

- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

  1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant clean up system, and are consistent with plant design bases.

  2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

  3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

  Note that the term “fuel damage” as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

  FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-20, Protection System Functions, is described in FSAR Section 3.1.2.20

  A fully automatic protection system, with appropriate redundant channels, is provided to cope with transients where insufficient time is available for manual corrective action. The design basis for all protection systems is IEEE Standard 279-1971 and IEEE Standard 379-1972. The reactor protection system automatically initiates a reactor trip when any variable exceeds the normal operating range. Setpoints are designed to provide an envelope of safe operating conditions with adequate margin for uncertainties to ensure that fuel design limits are not exceeded.

  Reactor trip is initiated by removing power to the rod drive mechanisms of all of the full length rod cluster control assemblies. This causes the rods to insert by gravity, which rapidly reduces reactor power output. The response and adequacy of the protection system have been verified by analysis of expected transients.

  The ESF actuation system automatically initiates emergency core cooling, and other safeguards functions, by sensing accident conditions using redundant analog channels measuring diverse variables. Manual actuation of safeguards equipment may be performed where ample time is available for operator action. The ESF actuation system automatically trips the reactor on manual or automatic SIS generation.

- GDC-25, Protections System Requirements for Reactivity Control Malfunctions, is described in FSAR Section 3.1.2.25.

  The protection system is designed to limit reactivity transients so that fuel design limits are not exceeded. Reactor shutdown by full length rod insertion is completely independent of the normal control function, since the trip breakers interrupt power to the rod mechanisms regardless of existing control signals. Thus, in the postulated accidental withdrawal (assumed to be initiated by a control malfunction), flux, temperature, pressure, level and flow signals would be generated independently. Any of these signals (trip demands) would operate the breakers to trip the reactor.

  FSAR Chapter 15 discusses analyses of the effects of possible malfunctions. These analyses show that for postulated dilution during refueling, startup or manual or automatic operation at power, the operator has ample time to determine the cause of dilution, terminate the source of dilution, and initiate boration before the shutdown margin is lost. The analyses show that acceptable fuel damage limits are not exceeded even in the event of a single malfunction of either system.

FSAR Section 15.4.3.1 states that RCCA misalignment accidents include a dropped full-length assembly, dropped full-length assembly bank, statically misaligned full-length assembly, and withdrawal of a single full-length assembly. The dropped assembly, dropped assembly bank, and statically misaligned assembly events are classified as ANS Condition II incidents and the single RCCA withdrawal incident is classified as an ANS Condition III event.

MPS3 Table 15.0-2 states that this transient is analyzed utilizing the THINC, TURTLE, LOFTRAN, and LEOPARD codes.

FSAR Section 15.4.3.3 concludes that:

- For cases of dropped single RCCAs or dropped banks, the DNBR remains greater than the limit value; therefore, the DNB design basis is met.
- For all cases of any RCCA fully inserted, or bank D inserted to its rod insertion limits with any single RCCA in that bank fully withdrawn (static misalignment), the DNBR remains greater than the limit value. Thus, the DNB design basis as described in FSAR Section 4.4 is met.
- For the case of the accidental withdrawal of a single RCCA, with the reactor in the manual control mode and initially operating at full power with bank D at the insertion limit, an upper bound of the number of fuel rods experiencing DNB is 5 percent of the total fuel rods in the core.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.4.3.2 Technical Evaluation

The specific acceptance criteria applied for this event are as follows:

- The DNBR should remain above the 95/95 DNBR limit at all times during the transient. Demonstrating that the DNBR limit is met satisfies the requirements of GDC-10.

- Per GDC-20, the protection system should be designed to automatically initiate the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs and to sense accident conditions and initiate the operation of safety-related systems and components. For this event, protection is provided via the overtemperature T trip, but only for the most limiting cases. The non-limiting cases considered do not require protection.
- GDC-25 requires that the protection system is designed to ensure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods. Demonstrating that the fuel design limits (i.e., DNBR) are met satisfies the requirements of GDC-25.

The discussion below demonstrates that all applicable acceptance criteria are met for this event at MPS3 at SPU conditions.

2.8.5.4.3.2.1 Introduction

The rod cluster control assembly (RCCA) misalignment events include the following:

- One or more dropped RCCAs from the same group
- A dropped RCCA bank
- A statically misaligned RCCA
- Withdrawal of a single RCCA

Each RCCA has a position indicator channel that displays the position of the assembly in a display grouping that is convenient to the operator. Fully inserted RCCAs are also indicated by a rod-at-bottom signal that actuates a control room annunciator. Group demand position is also indicated.

RCCAs move in preselected banks that always move in the same preselected sequence. Each control bank of RCCAs consists of two groups. The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or deactuation) of the stationary gripper, movable gripper, and lift coils of the control rod drive mechanism (CRDM) withdraws the RCCA held by the mechanism. Mechanical failures are in the direction of insertion or immobility.

A dropped RCCA or RCCA bank is detected by one or more of the following:

- Sudden drop in the core power level as seen by the nuclear instrumentation system
- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples
- Rod at bottom signal
- Rod deviation alarm
- Rod position indication

Dropping of a full-length RCCA is assumed to be initiated by a single electrical or mechanical failure that causes any number and combination of rods from the same group of a given control bank to drop to the bottom of the core. The resulting negative reactivity insertion causes nuclear power to rapidly decrease. An increase in the hot channel factor can occur due to the skewed power distribution representative of a dropped rod configuration. The automatic rod withdrawal feature of the rod control system has been disabled, therefore there is no control system interaction with this transient. For this event, it must be shown that the DNB design basis is met for the combination of power, hot channel factor, and other system conditions which exist following a dropped rod.

Misaligned assemblies are detected by:

- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples
- Rod deviation alarm
- Rod position indicators

For MPS3, the resolution of the rod position indicator channel is ±4 steps. The deviation alarm alerts the operator to rod deviation with respect to group demand position in excess of 12 steps. Deviation of any RCCA from its group by twice this distance (24 steps) does not cause power distributions worse than the design limits. If the rod deviation alarm is not operable, the operator is required to take action as required by the Technical Specifications.

In the extremely unlikely event of simultaneous electrical failures which could result in single RCCA withdrawal, rod deviation would be displayed on the plant annunciator, and the rod position indicators would indicate the relative positions of the assemblies in the bank. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications. Withdrawal of a single RCCA results in both positive reactivity insertion tending to increase core power, and an increase in local power density in the core area associated with the RCCA. Automatic protection for this event is provided by the Overtemperature ΔT reactor trip, although due to the increase in local power density it is not possible in all cases to provide assurance that the core safety limits are not violated.

2.8.5.4.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The dropped RCCA, dropped RCCA bank, and statically misaligned RCCA events are classified as Condition II events (faults of moderate frequency) as defined by the ANS. The single RCCA withdrawal incident is classified as an ANS Condition III event, as discussed below.

No single electrical or mechanical failure in the rod control system could cause the accidental withdrawal of a single RCCA from the inserted bank at full power operation. The operator could deliberately withdraw a single RCCA in the control bank since this feature is necessary in order to retrieve an assembly should one be accidentally dropped. The event analyzed must result from multiple wiring failures or multiple deliberate operator actions and subsequent and repeated operator disregard of event indication. The probability of such a combination of conditions is so low that the limiting consequences may include slight fuel damage. Thus, consistent with the philosophy and format of ANSI N18.2, the event is classified as a Condition III event. By definition “Condition III occurrences include incidents, any one of which may occur during the lifetime of a particular plant,” and “shall not cause more than a small fraction of fuel elements in the reactor to be damaged...”

2.8.5.4.3.2.3 Description of Analyses and Evaluations

One or More Dropped RCCAs from the Same Group

The LOFTRAN computer code calculates transient system responses for the evaluation of a dropped RCCA event. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and MSSVs. The code computes pertinent plant variables including temperatures, pressures, and power levels.

Transient RCS statepoints (temperature, pressure, and power) are calculated by LOFTRAN. Nuclear models are used to obtain a hot-channel factor consistent with the primary-system conditions and reactor power. By incorporating the primary conditions from the transient analysis and the hot-channel factor from the nuclear analysis, it is shown that the DNB design basis is met using dropped rod limit lines developed with the VIPRE code (Reference 1). The transient response analysis, nuclear peaking factor analysis, and performance of the DNB design basis confirmation are performed in accordance with the approved methodology described in Reference 2.

Dropped RCCA Bank

A dropped RCCA bank results in a symmetric power change in the core. Assumptions made in the methodology (Reference 2) for the dropped RCCA(s) analysis provide a bounding analysis for the dropped RCCA bank.

Statically Misaligned RCCA

Steady-state power distributions are analyzed using the appropriate nuclear physics computer codes. The peaking factors are then compared to peaking factor limits developed using the VIPRE code, which are based on meeting the DNBR design criterion. The following cases are examined in the analysis assuming the reactor is at full power: the worst rod withdrawn with bank D inserted at the insertion limit, the worst rod dropped with bank D inserted at the insertion limit, and the worst rod dropped with all other rods out. It is assumed that the incident occurs at the time in the cycle with maximum predicted peaking factors. This assures a conservative $F_{\Delta}H$ for the misaligned RCCA configuration.

Single RCCA Withdrawal

Core power distributions simulating a single RCCA withdrawal event are calculated using the computer code ANC. The case of the worst rod withdrawn from control bank D inserted at the insertion limit, with the reactor initially at full power, is identified and analyzed. The purpose of this calculation is to confirm that the number of fuel rods that experience DNB is less than the safety analysis limit of 5 percent. The ANC calculated peaking factors are compared to the design peaking factor used to set the overtemperature ΔT trip. Overtemperature ΔT trip setpoints are established to prevent exceeding DNBR limits. If the calculated peaking factors are above the design peaking factor limit, including appropriate calculational uncertainty, a fuel census is generated for the most limiting case to determine the percentage of rods in the core which exceed the design peaking factor. All rods which exceed the design peaking factor are assumed to undergo DNB prior to reaching the power and coolant conditions that would trip the plant on overtemperature ΔT.

The ANC calculations are performed at the time in core life which has the highest peak $F_{\Delta}H$. Power distributions are generated for unique combinations of control bank D inserted to the full power insertion limit, with one control bank D RCCA fully withdrawn. Xenon reconstruction is used to skew the axial flux difference to the upper allowable limit. The most limiting configuration is determined by the case that produces the highest peaking factors under these conditions.

The VIPRE and ANC codes have been used in this analysis instead of the THINC and TURTLE codes, which were used in the current licensing basis analysis. VIPRE and ANC have been approved by the NRC.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the RCCA misalignment analysis. As stated in Section 2.8.5.4.3.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.4.3.2.4 Results

One or More Dropped RCCAs

Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion. The core is not adversely affected during this period since power is decreasing rapidly. Either reactivity feedback or control bank withdrawal re-establishes power.

Following a dropped rod event with the automatic rod withdrawal feature disabled, the plant establishes a new equilibrium condition. Without control system interaction, a new equilibrium is achieved at a reduced power level and reduced primary temperature. In all cases, the minimum DNBR remains above the limit value.

Following plant stabilization, the operator may manually retrieve the RCCA(s) by following approved operating procedures. Plant operating procedures only permit the recovery of one dropped RCCA. If more than one RCCA is dropped, a reactor trip is manually initiated.

Dropped RCCA Bank

A dropped RCCA bank results in a large negative reactivity insertion. The core is not adversely affected during the insertion period, since power is decreasing rapidly. The transient proceeds similar to that described in the previous “One or More Dropped RCCAs” section. The negative reactivity worth of a dropped RCCA bank is generally larger than that caused by one or more dropped RCCAs from the same group. For this reason, the initial power reduction from a dropped RCCA bank is large and the power return due to reactivity feedback is far less than that seen from one or more dropped RCCAs from the same group. In either instance, the minimum DNBR remains above the limit value.

Statically Misaligned RCCA

The most severe RCCA misalignment situations with respect to DNB at significant power levels are associated with cases in which one RCCA is fully inserted with either all rods out or bank D at the insertion limit, or where bank D is inserted to the insertion limit and one RCCA is fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alert the operator well before the transient approaches the postulated conditions.

The insertion limits in the Technical Specifications may vary from time to time, depending on several limiting criteria. The full-power insertion limits on control bank D are to be above that position which meets the minimum DNBR and peaking factors. The full-power insertion limit is usually dictated by other criteria. Detailed results vary from cycle to cycle depending on fuel arrangements.

For the RCCA misalignment case with one RCCA fully inserted (with either all rods out or bank D at the insertion limit), the DNBR does not fall below the limit value. The analysis for this case assumes that the initial reactor power, RCS pressure, and RCS temperature are at nominal values with uncertainties included, and with the increased radial peaking factor associated with the misaligned RCCA.

Calculations have not been performed specifically for RCCAs missing from other control banks, which are permitted to be either fully or partially inserted at part power conditions. However, it has been determined on a generic basis that the increase in radial peaking factor necessary to reach the DNBR limit at reduced power conditions, is greater than the credible increase in radial peaking factors associated with reduced thermal power levels and deeper permitted control bank insertion. Therefore, the full power case discussed above with bank D at the insertion limit is more limiting than any credible part power RCCA misalignment scenario involving rods at the insertion limit.

For the RCCA misalignment case with bank D inserted to the full-power insertion limit and one RCCA fully withdrawn, the DNBR does not fall below the limit value. The analysis for this case assumes that the initial reactor power, RCS pressure, and RCS temperature are at nominal values with uncertainties included, and with the increased radial peaking factor associated with the misaligned RCCA.

Departure from nucleate boiling does not occur for the RCCA misalignment incident. Therefore, there is no reduction in the ability of the primary coolant to remove heat from the fuel rod. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The resulting linear heat generation rate is well below that which would cause fuel melting.

After identifying an RCCA group misalignment condition, the operator must take action as required by the plant Technical Specifications and operating procedures.

Single RCCA Withdrawal

Since the automatic rod withdrawal mode has been disabled, only the manual case for the single rod withdrawal event is considered. Continuous withdrawal of a single RCCA results in both an increase in core power and coolant temperature, and an increase in the local hot channel factor in the area of the withdrawing RCCA. In terms of the overall system response, this case is similar to a Statically Misaligned RCCA; however, the increased local power peaking in the area of the withdrawn RCCA may result in lower minimum DNBRs than for the withdrawn bank cases. Depending on initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur sufficiently fast to prevent the minimum core DNB ratio from falling below the limit value. Evaluation of this case at the power and coolant conditions at which the Overtemperature T trip would be expected to trip the plant shows that an upper limit for the number of rods with a DNBR less than the limit value is 5 percent.

For such cases as above, a reactor trip ultimately ensues, although not sufficiently fast in all instances to prevent a minimum DNBR in the core of less than the limit value. Following reactor trip, normal shutdown procedures are followed.

The evaluation of the dropped rod event using the methodology in Reference 2, encompassing all possible dropped RCCA or RCCA bank worths delineated in Reference 2, concluded that the minimum DNBR remains above the limit value. For all cases of any single RCCA fully inserted, or bank D inserted to the rod insertion limit and any single RCCA in that bank fully withdrawn (static misalignment), the minimum DNBR remains above the limit value. Therefore, the DNB design criterion is met and the RCCA misalignments do not result in core damage given implementation of the SPU Program. For the case of the accidental withdrawal of a single RCCA, with the reactor initially operating at full power with bank D at the insertion limit, an upper bound of the number of fuel rods experiencing DNB is 5 percent of the total number of fuel rods in the core.

2.8.5.4.3.3 Conclusion

DNC has reviewed the analyses of control rod misoperation events and concludes that the analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. DNC also concludes that the analyses were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs will not be exceeded during normal or anticipated operational transients. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -10, -20, and -25 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to control rod misoperation events.

2.8.5.4.3.4 References

1. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, October 1999.

2. WCAP-11394 (Proprietary) and WCAP-11395 (Nonproprietary), Methodology for the Analysis of the Dropped Rod Event, April 1987.

2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature and Boron Concentration

2.8.5.4.4.1 Regulatory Evaluation

A startup of an inactive loop transient may result in either an increased core flow or the introduction of cooler or deborated water into the core. This event causes an increase in core reactivity due to decreased moderator temperature or moderator boron concentration. This event is precluded by the Technical Specifications as discussed below. Thus, no additional DNC review was required.

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the RCS be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences (AOOs)
- GDC-15, insofar as it requires that the RCS and its associated auxiliary system be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during AOOs
- GDC-20, insofar as it requires that the protection system be designed to automatically initiate the operation of appropriate systems to ensure that the specified acceptable fuel design limits are not exceeded as a result of AOOs
- GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded
- GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core

Specific review criteria are contained in SRP Section 15.4.4-5, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 15.4.4-5, Rev. 1.

The reactor coolant loops are equipped with loop stop valves that permit any loop to be isolated from the reactor vessel. One valve is installed on each hot leg and one on each cold leg. The loop stop valves are used to perform maintenance on an isolated loop.

The safety analyses performed for the reactor at power assume that all reactor coolant loops are initially in operation and the loop stop valves are open. FSAR Section 15.4.4 states that the startup of an inactive loop is precluded by technical specifications and administrative procedures. MPS3 Limiting Condition for Operation (LCO) 3.4.1.5 places controls on the loop stop valves to ensure that the valves are not inadvertently closed in Modes 1, 2, 3 and 4.

MPS3 LCO 3.4.1.5 requires each RCS loop stop valve to be open and the power removed from the valve operator. This ensures that inadvertent closure of a loop stop valve does not occur. Operation in Modes 1 through 4 with a RCS loop stop valve closed is not permitted except for the mitigation of emergency or abnormal events. If a loop stop valve is closed for any reason, the required actions of Technical Specification 3.4.1.5 must be completed.

The inadvertent closure of a loop stop valve when the RCPs are operating will result in a partial loss of forced reactor coolant flow. If the reactor is at rated power at the time of the event, the effect of the partial loss of forced coolant flow is a rapid increase in the coolant temperature that could result in DNB with subsequent fuel damage if the reactor is not tripped by the Low Flow reactor trip. If the reactor is shutdown and a RCS loop is in operation removing decay heat, closure of the loop stop valve associated with the operating loop could also result in increasing coolant temperature and the possibility of fuel damage.

The loop stop valves have motor operators. If power is inadvertently restored to one or more loop stop valve operators, the potential exists for accidental closure of the affected loop stop valve(s) and the partial loss of forced reactor coolant flow. With power applied to a valve operator, only the interlocks prevent the valve from being operated. Although operating procedures and interlocks make the occurrence of this event unlikely, the prudent action is to remove power from the loop stop valve operators. MPS3 Action 3.4.1.5.a requires the power to be removed within a specific time frame or the plant placed in Mode 5 within a specified time frame.

Should a loop stop valve be closed in Modes 1 through 4, the affected valve must be maintained closed and the plant placed in Mode 5. Once in Mode 5, the isolated loop may be started in a controlled manner in accordance with MPS3 LCO 3.4.1.6, “Reactor Coolant System Isolated Loop Startup.” Opening the closed loop stop valve in Modes 1 through 4 could result in colder water or water at a lower boron concentration being mixed with the operating RCS loops resulting in positive reactivity insertion.

MPS3 Surveillance Requirement 4.4.1.5 requires periodic verification to ensure that the RCS loop stop valves are open, with power removed from the loop stop valve operators. The primary function of this Surveillance is to ensure that power is removed from the valve operators, since MPS3 Surveillance Requirement 4.4.1.1 requires periodic verification that all loops are operating and circulating reactor coolant, thereby ensuring that the loop stop valves are open.

In Modes 5 and 6, MPS3 LCO 3.4.1.6 requires a reactor coolant loop to remain isolated with power removed from the associated RCS loop stop valve operators until the temperature at the cold leg of the isolated loop is within 20°F of the highest cold leg temperature of the operating loops, and the boron concentration of the isolated loop is greater than or equal to the boron concentration required by MPS3 LCO 3.1.1.1.2 or 3.1.1.2 for Mode 5 or MPS3 LCO 3.9.1.1 for Mode 6. The requirement to maintain the isolated loop stop valves shut with power removed ensures that no reactivity addition to the core could occur due to the startup of an isolated loop. Verification of the boron concentration in an isolated loop prior to opening the first stop valve provides a reassurance of the adequacy of the boron concentration in the isolated loop.

Given that the startup of an inactive RCS loop is precluded by the Technical Specifications, DNC did not consider any SPU impacts associated with License Renewal due to this transient.

2.8.5.4.4.2 Technical Evaluation

As noted in the previous section, the startup of an inactive RCS loop is precluded by the Technical Specifications. This does not change for the proposed SPU, therefore it is not necessary to perform a technical evaluation. The acceptance criteria noted in Section 2.8.5.4.4.1 continue to be met.

2.8.5.4.4.3 Conclusion

DNC has reviewed the analyses of the inactive loop startup event and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -10, -15, -20, -26, and -28 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the increase in core flow event.

2.8.5.4.5 CVCS Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant

2.8.5.4.5.1 Regulatory Evaluation

Unborated water can be added to the RCS via the CVCS. This may happen inadvertently because of operator error or CVCS malfunction, and cause an unwanted increase in reactivity and a decrease in shutdown margin. The operator should stop this unplanned dilution before the shutdown margin is eliminated.

The DNC review covered:

- The conditions at the time of the unplanned dilution
- The causes
- The initiating events
- The sequence of events
- The analytical model used for analyses
- The values of parameters used in the analytical model
- The results of the analyses

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences (AOOs)
- GDC-15, insofar as it requires that the RCS and its associated auxiliary, control and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs
- GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded

Specific review criteria are contained in SRP Section 15.4.6, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants" (NUREG-0800), SRP Section 15.4.6, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3's design relative to:

- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

  1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant clean up system, and are consistent with plant design bases.

  2. Ensure return of the reactor to a safe state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

  3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

  Note that the term "fuel damage" as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

  FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-15, Reactor Coolant System Design, is described in FSAR Section 3.1.2.15.

  The design pressure and temperature for each component in the reactor coolant and associated auxiliary, control and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

  Additionally, RCPB components achieve a large margin of safety by the use of proven ASME materials and design codes; the use of proven fabrication techniques; nondestructive shop testing; and integrated hydrostatic testing of assembled components. FSAR Chapter 5 discusses the RCS design.

- GDC-26, Reactor Coolant System Redundancy and Capability, is described in FSAR Section 3.1.2.26.

  Two reactivity control systems are provided. They are the RCCAs and chemical shim (boric acid). The RCCAs are inserted into the core by the force of gravity.

  During operation, the shutdown rod banks are fully withdrawn. The rod control system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specific fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses, and the most reactive rod cluster is assumed to be in the fully withdrawn position.

The CVCS maintains the reactor in the cold shutdown state independent of the position of the control rods. It can compensate for xenon burnout transients.

FSAR Chapter 4 presents details of the construction of the RCCAs. FSAR Chapter 7 discusses their operation. FSAR Chapter 9 describes the means of controlling boric acid concentration.

FSAR Section 15.4.6.1 states that the CVCS malfunctions that are considered to result in a decrease of the boron concentration in the reactor coolant are the inadvertent opening of the primary water makeup control valve and failure of the blend system, either by controller or mechanical failure. The addition of unborated water to the RCS results in a positive reactivity insertion and an erosion of available shutdown margin. For at power and start-up conditions, Modes 1 and 2, the dilution accident erodes the shutdown margin made available through reactor trip. For shutdown mode initial conditions, Modes 3, 4, 5, and 6, the dilution accident erodes the shutdown margin inherent in the borated RCS inventory and that which may be provided by control rods (control and shutdown banks) made available through reactor trip. This event is classified as an ANS Condition II event.

FSAR Section 15.4.6.3 concludes that, for operating Modes 1 through 5, the results show that adequate time is available for the operator to manually terminate the source of dilution flow, assuming the specified shutdown margin requirements are met. Following termination of the dilution flow, the operator can initiate boration to recover the shutdown margin.

In addition, FSAR Section 15.4.6.3 states that no analysis is presented for Mode 6 operation since dilution during refueling is precluded by the Technical Specifications.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.4.5.2 Technical Evaluation

The specific acceptance criterion applied for these events is that adequate operator action time is available prior to a complete loss of shutdown margin. For boron dilution events in Modes 1 through 5, there must be at least 15 minutes from operator notification (i.e., first alarm) until shutdown margin is lost. For MPS3 a boron dilution event cannot occur during Mode 6 (Refueling) due to administrative controls which isolate the RCS from the potential source of unborated water. With shutdown margin maintained, there is no return to critical and no violation of the 95/95 DNBR limit (GDC-10), as well as no violation of the primary and secondary pressure limits (GDC-15). Furthermore, since a return to critical is precluded and fuel design limits are not exceeded, the requirements of GDC-26 are satisfied.

For Modes 1 and 2, the boron dilution analysis is performed to identify the amount of time available from alarm to total loss of shutdown margin. For Modes 3 through 5, the boron dilution event is analyzed to generate minimum shutdown margin requirements as a function of the critical boron concentration.

The discussion below demonstrates that all applicable acceptance criteria are met for this event at MPS3 at SPU conditions.

2.8.5.4.5.2.1 Introduction

Reactivity can be added to the core by feeding primary grade water into the RCS via the reactor makeup portion of the CVCS. Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. A boric acid blend system is provided to permit the operator to match the boron concentration of the reactor coolant makeup water during normal charging to the RCS boron concentration. As discussed below, the CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value that, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

2.8.5.4.5.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The opening of the primary water makeup control valves provides makeup to the CVCS and subsequently to the RCS, which can dilute the reactor coolant. Inadvertent dilution from this source can be readily terminated by closing the control valve. In order for makeup water to be added to the RCS at pressure, at least one charging pump must be running in addition to a primary makeup water pump.

The limiting dilution flow path is identified as the lowest resistance flow path for an unintentional dilution. The boron dilution analysis excludes deliberate dilution operations from considerations. During intentional boron dilution operations, the plant operators are keenly aware of and continuously monitor the dilution process in progress for any sign of deviation or malfunction, such that the possibility of an undetected malfunction is considered remote. This is a standard assumption in the boron dilution analysis methodology. Thus the limiting boron dilution flow path does not include either the normal dilute or the alternative dilute flow paths (these paths are used only for deliberate dilution operations). The limiting boron dilution flow path is the makeup flow path of the primary grade water system used in normal boration/blend operations.

The most probable limiting dilution event is the misoperation of the CVCS reactor makeup control system (RMCS). The specific accident scenario identified is the inadvertent operation of the primary makeup control valve (FCV-111A) and failure of the blend system (either by controller or mechanical failure) which permits the primary makeup water system to inject directly to the charging pump suction (at the volume control tank (VCT) outlet) without being blended with boric acid, at the maximum rate permitted by the piping system (FT-111 fails forcing FCV-111A in the full-open position). The limiting boron dilution flow rate for this scenario has been concluded to be a conservative 150 gpm for Modes 1 through 6.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of the pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or makeup water flow rates deviate from preset values as a result of system malfunction.

A CVCS malfunction is classified as an ANS Condition II event, a fault of moderate frequency. Criteria established for Condition II events are as follows:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the RCS and main steam systems (MSS) should be maintained below 110 percent of the design pressures.
- Fuel temperature and fuel clad strain limits should not be exceeded. The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt.

This event is analyzed to show that there is sufficient time for mitigation of an inadvertent boron dilution prior to the complete loss of shutdown margin. A complete loss of plant shutdown margin results in a return of the core to the critical condition causing an increase in the RCS temperature and heat flux. This could violate the safety analysis limit DNBR value and challenge the fuel and fuel cladding integrity. A complete loss of plant shutdown margin could also result in a return of the core to the critical condition causing an increase in RCS pressure. This could challenge the pressure design limit for the RCS.

If the minimum allowable shutdown margin is shown not to be lost, the condition of the plant at any point in the transient is within the bounds of those calculated for other Condition II transients. By showing that the above criteria are met for those Condition II events, it can be concluded that they are also met for the boron dilution event. Operator action is relied upon to preclude a complete loss of plant shutdown margin.

2.8.5.4.5.2.3 Description of Analyses and Evaluations

Dilution During Mode 6 - An analysis is not performed for an uncontrolled boron dilution accident during refueling. In this mode, the event is prevented by the Technical Specifications for all potentially unborated water paths to the CVCS to preclude the addition of unborated water to the reactor vessel via the CVCS. No changes to the Technical Specifications which preclude the event from occurring in Mode 6 are proposed to support the SPU.

Dilution During Mode 5 – Typically, the plant is maintained in the cold shutdown mode when RCS ambient temperatures are required. Occasionally, reduced RCS inventory may be necessary. Mode 5 can also be a transition mode to either refueling (Mode 6) or hot shutdown (Mode 4). The water level can be dropped to the midplane of the hot leg for maintenance work that requires the steam generators to be drained. Through the cycle, the plant may enter Mode 5 if reduced temperatures are required in containment or as the result of a Technical Specification action statement. The plant is maintained in Mode 5 at the beginning of cycle for start-up testing of certain systems. During this mode of operation, the control banks are fully inserted. The following conditions are assumed for an uncontrolled boron dilution during cold shutdown.

- The assumed dilution flow (150 gpm) is the best estimate maximum flow from the reactor makeup water system (RMWS) assuming multiple simultaneous failures of control valves.
- A minimum water volume (3885 ft^3) in the RCS is used. This is a conservative estimate of the active volume of the RCS while on one train of residual heat removal (RHR). This active volume does not include the reactor vessel upper head volume.

- A conservative boron worth coefficient was assumed, with variable boron worth as a function of the critical boron concentration.

When the water level is drained down to the midplane of the hot leg from a filled and vented condition in cold shutdown, an uncontrolled boron dilution accident may be prevented by administrative controls which isolate the RCS from the potential source of unborated water. Nevertheless, analysis has been performed for a Mode 5 drained case. The minimum water volume for this scenario in the RCS is 3624 ft^3.

Dilution During Mode 4 – In Mode 4, the plant is being taken from a short-term mode of operation, cold shutdown (Mode 5), to a long-term mode of operation, hot standby (Mode 3). Typically, the plant is maintained in the hot shutdown mode to achieve plant heatup before entering Mode 3. The plant is maintained in Mode 4 at the beginning of cycle for start-up testing of certain systems. Throughout the cycle, the plant enters Mode 4 if reduced temperatures are required in containment or as a result of a Technical Specification action statement. During this mode of operation, the control banks are fully inserted. In Mode 4 the primary coolant forced flow which provides mixing can be provided by either the RHR system or a reactor coolant pump, depending on system pressure. The following conditions are assumed for an uncontrolled boron dilution during hot shutdown.

- The assumed dilution flow (150 gpm) is the best estimate maximum flow from the RMWS multiple simultaneous failure of control valves.
- In this mode for MPS3, RCS flow is conservatively assumed to be provided by the RHR system. With no RCP in operation during hot shutdown (with the required RHR pumps in operation), a conservatively low RCS water volume (3885 ft^3) is used. This active volume does not include the reactor vessel upper head volume.
- A conservative boron worth coefficient was assumed, with variable boron worth as a function of critical boron concentration.

Dilution During Mode 3 – During this mode, rod control is in manual and the rods can be either withdrawn or inserted. In Mode 3, all reactor coolant pumps may not be in operation. In an effort to balance the heat loss through the RCS and the heat removal of the steam generators, one or more of the pumps may be off to decrease heat input into the system. In the approach to Mode 2, the operator must manually withdraw the control rods and may initiate a limited dilution according to shutdown margin requirements, but not simultaneously. If the shutdown or control banks are withdrawn, the dilution scenario is similar to the Mode 2 analysis where the failure to block the source range trip results in a reactor trip and immediate shutdown of the reactor. The dilution scenario is more limiting if the control rods are not withdrawn and the reactor is shut down by boron to the Technical Specifications' minimum requirement for Mode 3. The following conditions are assumed for an uncontrolled boron dilution during hot standby.

- The assumed dilution flow (150 gpm) is the maximum flow from the RMWS assuming multiple simultaneous failures of control valves.
- A minimum water volume (8760 ft^3) in the RCS is used. This volume corresponds to the active volume of the RCS with one RCP in operation, excluding the pressurizer and the surge

line. The volume specified here is conservative in that no consideration is given to mixing in the upper head region.

- A conservative boron worth coefficient was assumed, with variable boron worth as a function of critical boron concentration.

Dilution During Mode 2 - In this mode, the plant is being taken from one long-term mode of operation (Mode 3) to another (Mode 1). The plant is maintained in the start-up mode only for the purpose of start-up testing at the beginning of each cycle. All normal actions required to change power level, either up or down, require operator initiation. Assumed conditions at start-up require the reactor to have available at least 1.30 percent k shutdown margin. The following conditions are assumed for an uncontrolled boron dilution during start-up.

- The assumed dilution flow (150 gpm) is the maximum flow from the RMWS assuming multiple simultaneous failures of control valves.
- A minimum RCS water volume of 9934 ft^3. This active RCS volume for Mode 2 includes the reactor vessel plus the active loops. Non-mixing regions, i.e., the pressurizer and surge line, are not included.
- The initial boron concentration is assumed to be 2150 ppm, which is a conservative maximum value for the critical concentration at the condition of hot zero power, rods to insertion limits, and no xenon.
- The critical boron concentration following reactor trip is assumed to be 1950 ppm, corresponding to the hot zero power, all rods inserted (minus the most reactive RCCA), no xenon conditions. The 200 ppm change from the initial condition noted above is a conservative minimum value.

Mode 2 is a transitory operational mode in which the operator intentionally dilutes and withdraws control rods to take the plant critical. During this mode, the plant is in manual control with the operator required to maintain a high awareness of the plant status. For a normal approach to criticality, the operator must manually initiate a limited dilution and withdraw the control rods, a process that takes several hours. The Technical Specifications require that the shutdown margin shall be determined, prior to approaching criticality, to be above the minimum requirement by verifying that the predicted position of the rods is within the rod insertion limits, thus ensuring that the reactor did not go critical with the control rods below the insertion limits. Once critical, the power escalation must be sufficiently slow to allow the operator to manually block the source range reactor trip (nominally at 10^5 cps) after receiving P-6 from the intermediate range. Too fast of a power escalation (due to an unknown dilution) would result in reaching P-6 unexpectedly, leaving insufficient time to manually block the source range reactor trip. Failure to perform this manual action results in a reactor trip and immediate shutdown of the reactor.

However, in the event of an unplanned approach to criticality or dilution during power escalation while in Mode 2, the plant status is such that minimal impact results. The plant slowly escalates in power to a reactor trip on the power range neutron flux low setpoint. After reactor trip, there are more than 15 minutes available for operator action prior to return to criticality. Mode 2 results are summarized in Table 2.8.5.4.5-1.

Dilution During Mode 1 - In this mode, the plant can be operated in either automatic or manual rod control. With the reactor in manual control and no operator action taken to terminate the transient, the power and temperature rise cause the reactor to reach the power range high neutron flux trip setpoint or the overtemperature T trip setpoint, resulting in a reactor trip. In this case, the boron dilution transient up to the time of trip is essentially equivalent to an uncontrolled RCCA bank withdrawal at power. Following reactor trip, there are more than 15 minutes prior to criticality. This is sufficient time for the operator to determine the cause of dilution and isolate the reactor makeup water source before the available shutdown margin is lost.

With the reactor in automatic rod control the power and temperature increase from the boron dilution results in insertion of the control rods and a decrease in the available shutdown margin. As the dilution and rod insertion continue, the rod insertion limit alarms (low and low-low settings) and axial flux difference alarm alert the operator that a dilution is in progress, and that the Technical Specification requirement for shutdown margin may be challenged, at least 15 minutes prior to criticality. This is sufficient time to determine the cause of dilution and isolate the reactor makeup water source before the available shutdown margin is lost.

The effective reactivity addition rate primarily is a function of the dilution rate, boron concentration, and boron worth. The following conditions are assumed for an uncontrolled boron dilution during full power.

- The assumed dilution flow (150 gpm) is the maximum flow from the RMWS assuming multiple simultaneous failures of control valves.
- A minimum RCS water volume of 9934 ft^3 is modeled. This corresponds to a conservative estimate of the active RCS volume excluding the pressurizer and surge line.
- The initial boron concentration is assumed to be 2150 ppm, which is a conservative maximum value for the critical concentration at the condition of hot full power, rods to insertion limits, and no xenon.
- The critical boron concentration following reactor trip is assumed to be 1950 ppm, corresponding to the hot zero power, all rods inserted (minus the most reactive RCCA), no xenon condition. The 200 ppm change from the initial condition noted above is a conservative minimum value.
- A 1.3 percent minimum shutdown margin is assumed in the analysis.
- Bounding boron worths of -15 and -5 pcm/ppm are conservatively considered. The larger absolute value maximizes the reactivity insertion rate, while the smaller absolute value minimizes the reactivity insertion rate thereby delaying the time to reach the reactor trip setpoint.

The analysis described above used a uniform mixing model and conservatively small mixing volumes for each mode. In the operating modes addressed in this section, sufficient coolant flow in the RCS is maintained by combinations of reactor coolant pumps and /or residual heat removal pumps (depending on the mode) to ensure adequate mixing.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the boron dilution analysis. As stated in Table 2.8.5.4.5-1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.4.5.2.4 Results

The boron dilution analysis demonstrated that all applicable acceptance criteria are met. This means that operator action to terminate the dilution flow within 15 minutes from operator notification from Modes 1, 2, 3, 4 and 5 precludes a complete loss of shutdown margin. The results of the boron dilution analysis and a comparison to previous results are provided in Table 2.8.5.4.5-1. Note that the previous analyses assume a difference between the initial and critical boron concentrations of 500 ppm compared to a more conservative difference of 200 ppm in the SPU analyses.

No analysis is presented for Mode 6 operation since dilution during refueling is precluded by the Technical Specifications.

If an unintentional dilution of boron in the RCS does occur, numerous alarms and indications are available to alert the operator to the condition. The maximum reactivity addition due to the dilution is slow enough to allow the operator sufficient time to determine the cause of the addition and take corrective action before shutdown margin is lost. The acceptance criteria as specified in Section 2.8.5.4.5.2.2 are met.

2.8.5.4.5.3 Conclusion

DNC has reviewed the analyses of the decrease in boron concentration in the reactor coolant due to a CVCS malfunction and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs -10, -15, and -26 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the decrease in boron concentration in the reactor coolant due to a CVCS malfunction.

Table 2.8.5.4.5-1
CVCS Malfunction Boron Dilution Event Results and Comparison to Previous Results

Case *	SPU Analysis (minutes)	Previous Analysis (minutes)	Limit (minutes)
Available Operator Action Time in Mode 1 – Manual Rod Control	30.3	77.6	15
Available Operator Action Time in Mode 1 – Automatic Rod Control	33.8	98.7	15
Available Operator Action Time in Mode 2	35.6	82.9	15
Available Operator Action Time in Mode 3	The maximum critical boron concentration controlled as a function of the plant initial boron concentration to meet a minimum operator action time of 15 minutes		15
Available Operator Action Time in Mode 4			15
Available Operator Action Time in Mode 5 – Drained			15
Available Operator Action Time in Mode 5 – Filled			15
Available Operator Action Time in Mode 6	N/A		

* For each case, the initial boron concentration and the critical boron concentration are verified on a cycle specific basis. The initial and critical boron concentrations used for the SPU analyses were optimized to facilitate reload evaluations. As such, the differences noted between the SPU results and the previous analysis results in the table above are not a direct result of the SPU conditions.

2.8.5.4.6 Spectrum of Rod Cluster Control Assembly Ejection Accidents

2.8.5.4.6.1 Regulatory Evaluation

RCCA ejection accidents cause a rapid positive reactivity insertion together with an adverse core power distribution, which could lead to localized fuel rod damage. DNC evaluated the consequences of a RCCA ejection accident to determine the potential damage caused to the RCPB and to determine whether the fuel damage resulting from such an accident could impair cooling water flow.

The DNC review covered:

- The initial conditions
- The rod patterns and worths, scram worth as a function of time, and reactivity coefficients
- The analytical model used for analyses
- The core parameters that affect the peak reactor pressure or the probability of fuel rod failure
- The results of the transient analyses.

The acceptance criteria are based on:

- GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core.

Specific review criteria are contained in SRP Section 15.4.8, and guidance provided in Matrix 1 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), Section 15.4.8, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to:

- GDC-28 is described in FSAR Section 3.1.2.28.

  The maximum positive reactivity worth of control rods and the maximum rates of reactivity insertion employing control rods are limited to values that prevent rupture of the RCS boundary or disruptions of the core or vessel internals to a degree that could impair the effectiveness of emergency core cooling.

  The maximum positive reactivity insertion rates for the withdrawal of RCCAs and the dilution of the boric acid in the RCS are limited by the physical design characteristics of the RCCAs and of the CVCS. Technical Specifications on shutdown margin and on RCCA insertion limits and bank overlaps as functions of power provide additional assurance that the consequences of the postulated accidents are no more severe than those presented in the analyses of FSAR Chapter 15. Reactivity insertion rates, dilution, and withdrawal limits are also discussed in FSAR Section 4.3. The capability of the CVCS to avoid an inadvertent excessive rate of boron dilution is discussed in FSAR Chapter 15.

Assurance of core cooling capability following Condition IV accidents, such as rod ejections, steam line breaks, etc., is given by keeping the RCPB stresses within faulted condition limits as specified by applicable ASME Codes. Structural deformations are also checked and limited to values that do not jeopardize the operation of necessary safety features.

FSAR Section 15.4.8.1 states that a RCCA ejection accident is defined as the mechanical failure of a control rod mechanism pressure housing, resulting in the ejection of a 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. FSAR Section 15.4.8.1.2 states that this event is classified as an ANS Condition IV incident.

FSAR Table 15.0-2 states that this transient was analyzed utilizing the TWINKLE, FACTRAN, and THINC codes.

FSAR Section 15.4.8.3 states that the analyses conclude that the described fuel and clad limits are not exceeded, and there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, there is no danger of further consequential damage to the RCS. The analyses have demonstrated that less than 10 percent of the fuel rods entered DNB.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.4.6.2 Technical Evaluation

The criterion applied by DNC to ensure the core remains in a coolable geometry following a rod ejection incident is that the average fuel pellet enthalpy at the hot spot must remain less than 200 cal/g (360 Btu/lbm). The use of the initial conditions presented in Table 2.8.5.4.6-1 resulted in conservative calculations of the fuel pellet enthalpy. The results of the licensing basis analyses demonstrated that the fuel pellet enthalpy does not exceed 200 cal/g for any of the rod ejection cases analyzed.

Overpressurization of the RCS during a rod ejection event is generically addressed in WCAP-7588, Revision 1-A (Reference 1).

Another applicable acceptance criterion is that fuel melting must be limited to less than the innermost 10 percent of the fuel pellet at the hot spot, even if the average fuel pellet enthalpy at the hot spot is less than the limit of 200 cal/g. Conservative fuel melt temperatures of 4900°F and 4800°F were assumed for the hot spot for the beginning-of-life (BOL) and end-of-life (EOL) cases, respectively. The results of the licensing basis rod ejection analyses demonstrated that the amount of fuel melting was limited to less than 10 percent of the fuel pellet at the hot spot for each of the rod ejection cases.

2.8.5.4.6.2.1 Introduction

This accident is defined as a mechanical failure of a control rod drive mechanism (CRDM) pressure housing resulting in the ejection of the 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. The resultant core thermal power excursion is limited by the Doppler reactivity effect of the increased fuel temperature and terminated by reactor trip actuated by high nuclear power signals.

The mechanical design and quality control procedures intended to preclude the possibility of an RCCA drive mechanism housing failure are listed below:

- Each full-length CRDM housing is completely assembled and shop tested at 4100 psig.
- The mechanism housings are individually hydrotested after they are attached to the head adapters in the reactor vessel head and checked during the hydrotest of the completed RCS.
- Stress levels in the mechanism are not affected by anticipated system transients at power or by the thermal movement of the coolant loops. Moments induced by the design earthquake can be accepted within the allowable primary working stress ranges specified in the ASME Boiler and Pressure Vessel Code, Section III (Reference 2), for Class I components.
- The latch mechanism housing and rod travel housing are each a single length of forged type-304 stainless steel. This material exhibits excellent notch toughness at all temperatures that may be encountered.

A significant amount of margin of strength in the elastic range, together with the large energy absorption capability in the plastic range, gives additional assurance that the gross failure of the housing does not occur. The joints between the latch mechanism housing and rod travel housing are threaded joints and reinforced by canopy-type rod welds.

In general, the reactor is operated with the RCCAs inserted only far enough to control design neutron flux shape. Reactivity changes caused by the core depletion are compensated by boron changes. Furthermore, the location and grouping of control rod banks are selected during the nuclear design to lessen the severity of an RCCA ejection accident. Therefore, if an RCCA is ejected from its normal position during full-power operation, only a minor reactivity excursion, at worst, could be expected to occur. The position of all of the RCCAs is continuously indicated in the control room. An alarm occurs if a bank of RCCAs approaches its insertion limit or if one control rod assembly deviates from its bank. There are low and low-low level insertion alarm circuits for each bank. The control rod position monitoring and alarm systems are described in WCAP-7588 (Reference 1).

2.8.5.4.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input parameters for the analysis were conservatively selected on the basis of values calculated for this type of core. The most important parameters are discussed below. Table 2.8.5.4.6-1 presents the parameters used in this analysis.

Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors were calculated using either three-dimensional (3-D) static methods or a synthesis of one-dimensional (1-D) and two-dimensional (2-D) calculations. Standard nuclear design codes were used in the analysis. No credit was taken for the flux-flattening effects of reactivity feedback. The calculation was performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. The analysis assumed adverse xenon distributions to provide worst-case results. Appropriate margins were added to the ejected rod worth and hot channel factors to account for any calculational uncertainties.

Delayed Neutron Fraction, β_{eff}

Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values of approximately 0.75 percent at BOL and 0.40 percent at EOL. The ejected rod accident is sensitive to β_{eff} if the ejected rod worth is equal to or greater than β_{eff}, as in the zero-power transients. In order to allow for future fuel cycle flexibility, conservative estimates of β_{eff} of 0.50 percent at beginning of cycle and 0.40 percent at end of cycle were used in the analysis.

Reactivity Weighting Factor

The largest temperature rises, and hence the largest reactivity feedbacks, occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback was larger than that indicated by a simple single-channel analysis. Physics calculations were performed for temperature changes with a flat temperature distribution and a large number of axial and radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors took the form of multipliers that, when applied to single-channel feedbacks, corrected them to effective whole-core feedbacks for the appropriate flux shape. In this analysis, a one-dimensional (axial) spatial kinetics method is employed, thus axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors have also been shown to be conservative compared to three-dimensional analysis.

Moderator and Doppler Coefficient

The critical boron concentrations at BOL and EOL were adjusted in the nuclear code in order to obtain moderator density coefficient curves that were conservative when compared to the actual design conditions for the plant. As discussed above, no weighting factor was applied to these results. The resulting MTC was +5 pcm/°F at zero-power nominal T_{avg} and 0 pcm/°F at full-power T_{avg} for the BOL cases. The EOL cases assume MTCs of -16.8 pcm/°F and -22.9 pcm/°F for the zero-power and full-power cases, respectively.

The Doppler reactivity defect was determined as a function of power level using a 1-D steady-state computer code with a Doppler weighting factor of 1.0. The Doppler weighting factor increased under accident conditions, as discussed above.

Heat Transfer Data

The FACTRAN (Reference 3) code, used to determine the hot spot transient, contains standard curves of thermal conductivity versus fuel temperature. During a transient, the peak centerline fuel temperature is independent of the gap conductance during the transient. The cladding temperature is, however, strongly dependent on the gap conductance and is highest for high gap conductance. For conservatism, a low initial gap heat transfer coefficient was used at the beginning of the transient to maximize the initial fuel temperature, and a high gap heat transfer coefficient value of 10,000 Btu/hr-ft^2-°F was used for the remainder of the transient to maximize the clad temperature. This value corresponded to a negligible gap resistance and a further increase would have essentially no effect on the rate of heat transfer.

Coolant Mass Flow Rates

When the core is operating at full power, all four coolant pumps always operate. For zero power conditions, the system was conservatively assumed to be operating with two pumps. The principal effect of operating at reduced flow is to reduce the film boiling heat transfer coefficient. This resulted in higher peak cladding temperatures, but did not affect the peak centerline fuel temperature. Reduced flow also lowers the critical heat flux. However, since DNB was always assumed at the hot spot, and since the heat flux rose very rapidly during the transient, this produced only second order changes in the cladding and centerline fuel temperatures.

Trip Reactivity Insertion

The trip reactivity insertion was assumed to be 4.0 percent Δk from hot full power (HFP) and 2.0 percent Δk from hot zero power, including the effect of one stuck RCCA. These values were also reduced by the ejected rod reactivity. The shutdown reactivity was simulated by dropping a rod of the required worth into the core. The start of rod motion occurred 0.5 second after reaching the power range high neutron flux trip setpoint. It was assumed that insertion to dashpot did not occur until 2.7 seconds after the rods began to fall. The time delay to full insertion, combined with the 0.5 second trip delay, conservatively delayed insertion of shutdown reactivity into the core.

Due to the extremely low probability of an RCCA ejection accident, this event is classified as an ANS Condition IV event. As such, some fuel damage is considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold of significant conversion of the fuel thermal energy to mechanical energy were carried out as part of the SPERT project by the Idaho Nuclear Corporation (Reference 4). Extensive tests of UO_2 zirconium-clad fuel rods representative of those present in pressurized water reactor (PWR) type cores have demonstrated failure thresholds in the range of 240 to 257 cal/g. However, other rods of a slightly different design exhibited failure as low as 225 cal/g. These results differ significantly from the TREAT (Reference 5) results that indicated a failure threshold of 280 cal/g. Limited results have indicated that this threshold decreased 10 percent with fuel burnup. The clad failure mechanism appeared to be melting for unirradiated (zero burnup) rods and brittle fracture for irradiated rods. The conversion ratio of thermal to mechanical energy is also important. This ratio became marginally detectable above 300 cal/g for unirradiated rods and 200 cal/g for irradiated rods; catastrophic failure (large fuel dispersal, large pressure rise), even for irradiated rods, did not occur below 300 cal/g.

The real physical limits of this accident were that the rod ejection event and any consequential damage to either the core or the RCS must not prevent long-term core cooling, and any offsite dose consequences must be within the guidelines of 10 CFR 50.67 (Reference 6). More-specific and restrictive criteria were applied to ensure no fuel dispersal in the coolant. Gross lattice distortion or severe shock waves did not occur. In view of the above experimental results and the conclusions of WCAP-7588, Rev. 1-A (Reference 1), the limiting criteria were:

- Average fuel pellet enthalpy at the hot spot must be maintained below 225 cal/g for unirradiated and 200 cal/g (360 Btu/lbm) for irradiated fuel (the 200 cal/g limit is applied).
- Peak reactor coolant pressure must be less than that which could cause RCS stresses to exceed the faulted-condition stress limits (note: the peak pressure aspects of the rod ejection transient are addressed generically in Reference 1).
- Fuel melting is limited to less than 10 percent of the pellet volume at the hot spot even if the average fuel pellet enthalpy is below the 200 cal/g fuel enthalpy limit.

2.8.5.4.6.2.3 Description of Analyses and Evaluations

This section describes the models used in the analysis of the rod ejection accident. Only the initial few seconds of the power transient are discussed, since the long-term considerations are the same as for a small loss of coolant accident (LOCA).

The calculation of the RCCA ejection transient was performed in two stages, first an average core channel calculation, and then a hot region calculation. The average core calculation used spatial neutron-kinetics methods to determine the average power generation with time including the various total core feedback effects; i.e., Doppler reactivity and moderator reactivity. Enthalpy and temperature transients at the hot spot were then determined by multiplying the average core energy generation by the hot channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback was conservatively assumed to persist throughout the transient. A detailed discussion of the method of analysis can be found in Reference 1.

Average Core

The spatial-kinetics computer code, TWINKLE (Reference 7) was used for the average core transient analysis. This code solves the two-group neutron diffusion theory kinetic equation in one, two, or three spatial dimensions (rectangular coordinates) for six delayed neutron groups and up to 2000 spatial points. The computer code includes a detailed multi-region, transient fuel-clad-coolant heat transfer model for calculation of pointwise Doppler and moderator feedback effects. This analysis used the code as a 1-D axial kinetics code since it allows a more realistic representation of the spatial effects of axial moderator feedback and RCCA movement. However, since the radial dimension was missing, it was still necessary to employ very conservative methods (described below) of calculating the ejected rod worth and hot channel factor.

Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal heat flux times the design hot channel factor. During the transient, the heat flux hot channel factor is linearly increased to the transient value in 0.1 second, the time for full ejection of the rod. Therefore, the assumption is made that the hot spot before and after ejection are coincident. This is very conservative since the peak after ejection occurs in or adjacent to the assembly with the ejected rod, and prior to ejection the power in this region is necessarily depressed.

The average core energy addition, calculated as described above, was multiplied by the appropriate hot channel factors. The hot spot analysis used the detailed fuel and clad transient heat transfer computer code, FACTRAN (Reference 3). This computer code calculates the transient temperature distribution in a cross section of a metal clad UO_2 fuel rod, and the heat flux at the surface of the rod, using the nuclear power versus time and local coolant conditions as input. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A parabolic radial power distribution was assumed within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before DNB, and the Bishop-Sandberg-Tong correlation (Reference 8) to determine the film boiling coefficient after DNB. The Bishop-Sandberg-Tong correlation was conservatively used assuming zero bulk fluid quality. The DNB heat flux was not calculated; instead the code was forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient could be calculated by the code; however, it was adjusted to force the full-power, steady-state temperature distribution to agree with fuel heat transfer design codes.

Fuel melting is represented in the FACTRAN code by assuming that melting occurs over a 5°F temperature range instead of at a constant temperature. This is performed in the code by setting the value of specific heat (c_p) in this range such that c_p times 5°F is equal to the latent heat of fusion of the material. The percentage of fuel pellet reaching melting is then calculated by FACTRAN based on the temperature above melting in each of the pellet volumetric zones represented, and the volume of the zone. For MPS3, ten fuel pellet zones were used in the FACTRAN calculation for the RCCA ejection event. The fuel melt temperature for the initiation of the fuel melting is conservatively set to a low value by the user input to the code.

Reactor Protection

The protection for this accident, as explicitly modeled in the analysis, was provided by the power range high neutron flux trip (high and low settings). The power range high neutron flux positive rate trip complements the high and low flux trip functions to ensure that the criteria were met for rod ejection from partial power. The single failure assumed is a failure of one train of the reactor protection system to initiate a reactor trip. Due to the redundancy in this trip function, this does not prevent the occurrence of a reactor trip. Since the transient is essentially over after the actuation of the reactor trip, no other single failure would contribute to increasing the severity of the transient. A loss of offsite power and subsequent RCP flow coastdown is typically only assumed if the reactor safeguard functions are actuated. There is no requirement to assume a loss of offsite power (LOOP) for this event. Nevertheless, since the minimum DNBR is reached shortly after the reactor trip is initiated, a LOOP would have no significant effect on the results.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the rod ejection analysis. As stated in Section 2.8.5.4.6.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.4.6.2.4 Results

The results of the analyses performed for the rod ejection event, which cover BOL and EOL conditions at HFP and HZP, are discussed below.

Beginning of Cycle, Zero Power

The worst ejected rod worth and hot channel factor were conservatively calculated to be 0.78 percent Δk, and 11.5, respectively. The peak hot spot average fuel pellet enthalpy reached 152.4 cal/g. The peak fuel centerline temperature never reached the BOL melt temperature of 4900°F, so no fuel melting is predicted.

Beginning of Cycle, Full Power

Control bank D was assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor were conservatively calculated to be 0.25 percent Δk and 6.0, respectively. The peak hot spot average fuel pellet enthalpy reached 175.8 cal/g. The peak fuel centerline temperature reached the BOL melt temperature of 4900°F; however, fuel melting remained well below the limiting criterion of 10 percent of total pellet volume at the hot spot.

End of Cycle, Zero Power

The worst ejected rod worth and hot channel factor were conservatively calculated to be 0.85 percent Δk and 26.0, respectively. The peak hot spot average fuel pellet enthalpy reached 158.3 cal/g. The peak fuel centerline temperature never reached the EOL melt temperature of 4800°F, so no fuel melting is predicted.

End of Cycle, Full Power

Control bank D was assumed to be inserted to its insertion limit. The ejected rod worth and hot channel factors were conservatively calculated to be 0.25 percent Δk and 7.0, respectively. The peak hot spot average fuel pellet enthalpy reached 173.7 cal/g. The peak fuel centerline temperature reached melting, conservatively assumed at 4800°F; however, fuel melting remained well below the limiting criterion of 10 percent of the pellet volume at the hot spot.

A summary of the parameters used in the rod ejection analyses, and the analyses results, are presented in Table 2.8.5.4.6-1. The sequence-of-events for all four cases is presented in Table 2.8.5.4.6-2. Figure 2.8.5.4.6-1 shows the transient curves for the BOL/HZP case; Figure 2.8.5.4.6-2 shows the transient curves for the BOL/HFP case. Figure 2.8.5.4.6-3 shows the transient curves for the EOL/HZP case; and Figure 2.8.5.4.6-4 shows the transient curves for the EOL/HFP case. Numerical results of the SPU analysis along with a comparison to the previous analysis results are shown in Table 2.8.5.4.6-3. The SPU analyses are only slightly different from the previous analyses. The previous analyses used overly conservative reactivity coefficients and the excess conservatism in the reactivity coefficients has been removed from the

SPU analyses. The removal of the excess conservatism partially offsets the penalty associated with the increased power. It should be pointed out that the reactivity coefficients assumed in the SPU analyses remain conservative and are revalidated as conservative for each subsequent reload. Table 2.8.5.4.6-1 shows the ejected rod worths and ejected F_Qs assumed in the analyses.

It should be noted that even with the reported value of fuel pellet melting, the maximum reported radially-averaged peak fuel enthalpy at the hot spot of 175.8 cal/g was well within the analysis limit of 200 cal/g for this event.

A detailed calculation of the pressure surge for an ejected rod worth of 1 dollar at BOL, HFP, indicates that the peak pressure did not exceed that which would cause reactor pressure vessel stress to exceed the faulted condition stress limits (Reference 1). Since the severity of the present analysis did not exceed the "worst-case" analysis, the accident for MPS3 at SPU conditions does not result in an excessive pressure rise or further adverse effects to the RCS.

Despite the conservative assumptions, the analyses indicate that the described fuel and clad limits were not exceeded. It was concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure did not exceed that which would cause stresses to exceed the faulted condition stress limits, it was concluded that there is no danger of further consequential damage to the RCS. Generic analyses demonstrated that the fission product release as a result of fuel rods entering DNB was limited to less than 10 percent of the fuel rods in the core.

2.8.5.4.6.3 Conclusion

DNC has reviewed the analyses of the rod ejection accident and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could (1) result in damage to the RCPB greater than limited local yielding, or (2) cause sufficient damage that would significantly impair the capability to cool the core. Based on this, DNC concludes that the plant will continue to meet the requirements of GDC-28 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the rod ejection accident.

2.8.5.4.6.4 References

1. WCAP-7588; Rev. 1-A, An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors using Special Kinetics Methods, January 1975.

2. American Society of Mechanical Engineers, Section III, The American Society of Mechanical Engineers, New York.

3. WCAP-7908-A, FACTRAN, A FORTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989.

4. IN-1370, Annual Report – SPERT Project, October 1968 – September 1969, Idaho Nuclear Corporation, June 1970.

5. Studies in TREAT of Zircaloy 2-Clad, UO_2-Core Simulated Fuel Elements, ANL-7225, p. 177, November 1966.

6. 10 CFR 50.67, Accident Source Term.

7. WCAP-7979-P-A, January 1975 (Proprietary) and WCAP-8028-A, January 1975 (Nonproprietary) TWINKLE, A Multi-Dimensional Neutron Kinetics Computer Code

8. ASME 65-HT-31, Forced Convection Heat Transfer at High Pressure After the Critical Heat Flux, August 1965.

Table 2.8.5.4.6-1
Parameters and Results of the Limiting RCCA Ejection Analysis

	Beginning of Cycle	Beginning of Cycle	End of Cycle	End of Cycle
Core Power Level, MWt	3650	0	3650	0
Ejected Rod Worth,% Δk	0.25	0.78	0.25	0.85
Delayed Neutron Fraction, %	0.50	0.50	0.40	0.40
Feedback Reactivity Weighting	1.3551	2.0807	1.4859	3.7649
Trip Reactivity, % Δk	4.0	2.0	4.0	2.0
F_Q Before Rod Ejection	2.60	--	2.60	--
F_Q after Rod Ejection	6.0	11.5	7.0	26.0
Number of Operational Pumps	4	2	4	2
Max Fuel Pellet Average Temperature, °F	4028	3575	3988	3690
Max Fuel Centerline Temperature, °F	4966	4096	4874	4115
Max Clad Average Temperature, °F	2251	2684	2224	2899
Max Fuel Stored Energy, cal/g	175.8	152.4	173.7	158.3
Fuel Melt at the Hot Spot, %	4.66	0	6.86	0

Table 2.8.5.4.6-2
Time Sequence of Events – RCCA Ejection

Event	Time (sec)	
	BOL HFP	**EOL HFP**
Initiation of Rod Ejection	0.0	0.0
Power Range High Neutron Flux Setpoint Reached	0.04	0.03
Peak Nuclear Power Occurs	0.14	0.13
Rods Begin to Fall	0.54	0.53
Peak Fuel Average Temperature Occurs	2.23	2.27
Peak Clad Temperature Occurs	2.31	2.33
Peak Heat Flux Occurs	2.32	2.34
	BOL HZP	EOL HZP
Initiation of Rod Ejection	0.0	0.0
Power Range High Neutron Flux Setpoint Reached	0.25	0.18
Peak Nuclear Power Occurs	0.30	0.21
Rods Begin to Fall	0.75	0.68
Peak Heat Flux Occurs	2.25	1.54
Peak Clad Temperature Occurs	2.25	1.54
Peak Fuel Average Temperature Occurs	2.43	1.80

Table 2.8.5.4.6-3
RCCA Ejection Results and Comparison to Previous Licensing Basis Results

Beginning of Cycle Cases					
	BOL/HFP SPU	**BOL/HFP Previous**	**BOL/HZP SPU**	**BOL/HZP Previous**	**Limit**
Max Fuel Stored Energy, cal/g	175.8	181.5	152.4	150.9	200
Fuel Melt at the Hot Spot, %	4.66	8.92	0.0	0.0	10
Max Clad Average Temperature, °F	2251	2258	2684	2624	3000
Reacted Zirc, %	0.91	0.90	3.01	2.65	16
End of Cycle Cases					
	EOL/HFP SPU	**EOL/HFP Previous**	**EOL/HZP SPU**	**EOL/HZP Previous**	**Limit**
Max Fuel Stored Energy, cal/g	173.7	170.6	158.3	148.9	200
Fuel Melt at the Hot Spot, %	6.86	5.71	0.0	0.0	10
Max Clad Average Temperature, °F	2224	2161	2899	2682	3000
Reacted Zirc, %	0.88	0.73	4.39	2.82	16

Figure 2.8.5.4.6-1
Rod Ejection – BOL/HZP Case

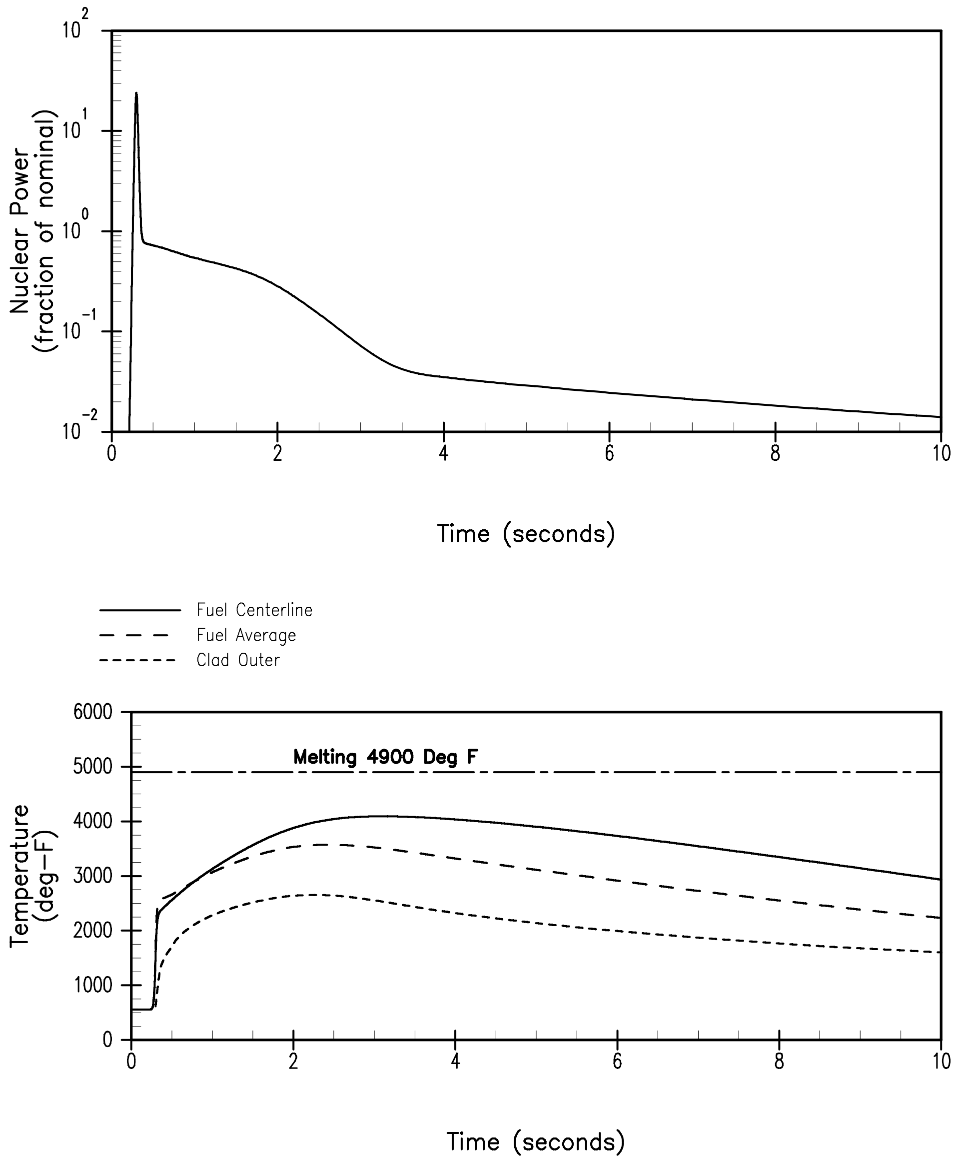
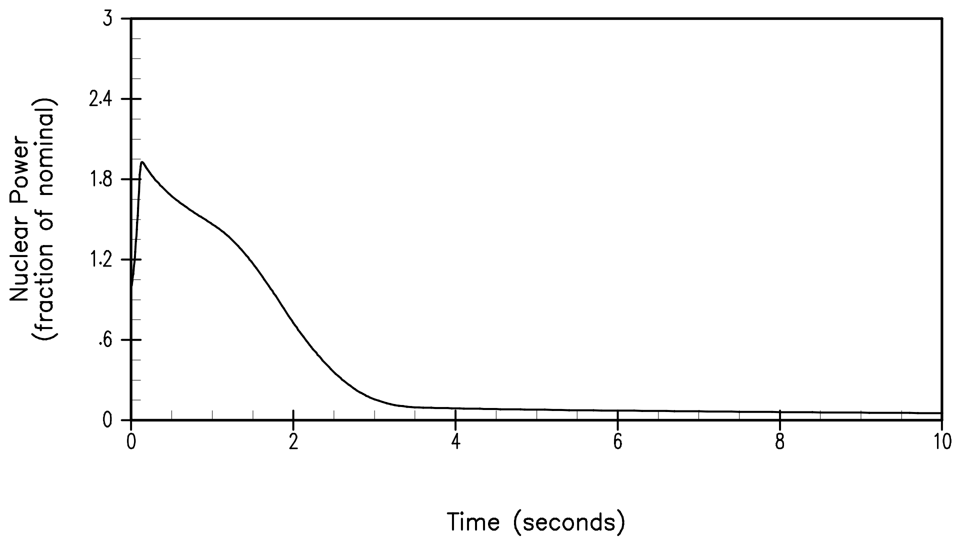


Figure 2.8.5.4.6-2
Rod Ejection – BOL/HFP Case



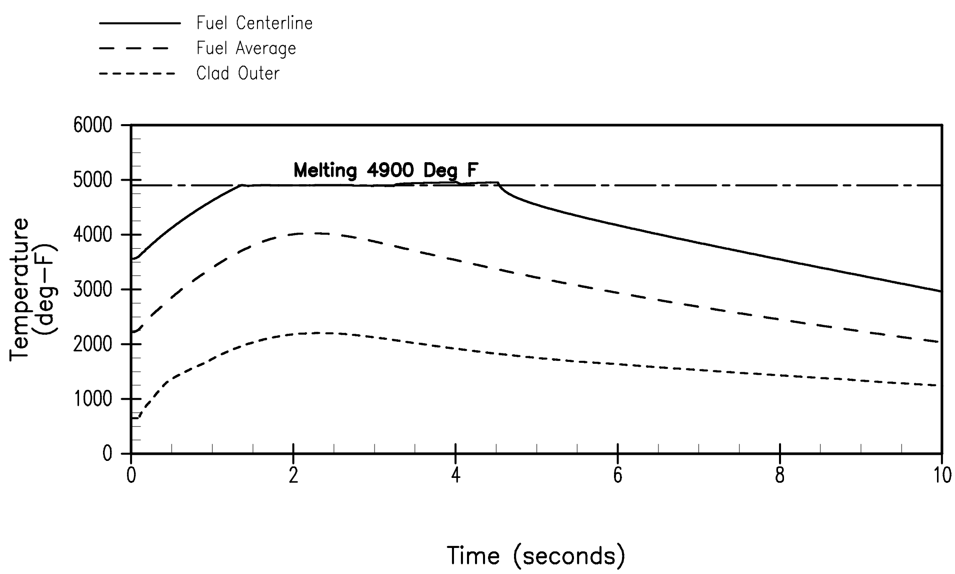


Figure 2.8.5.4.6-3
Rod Ejection – EOL/HZP Case

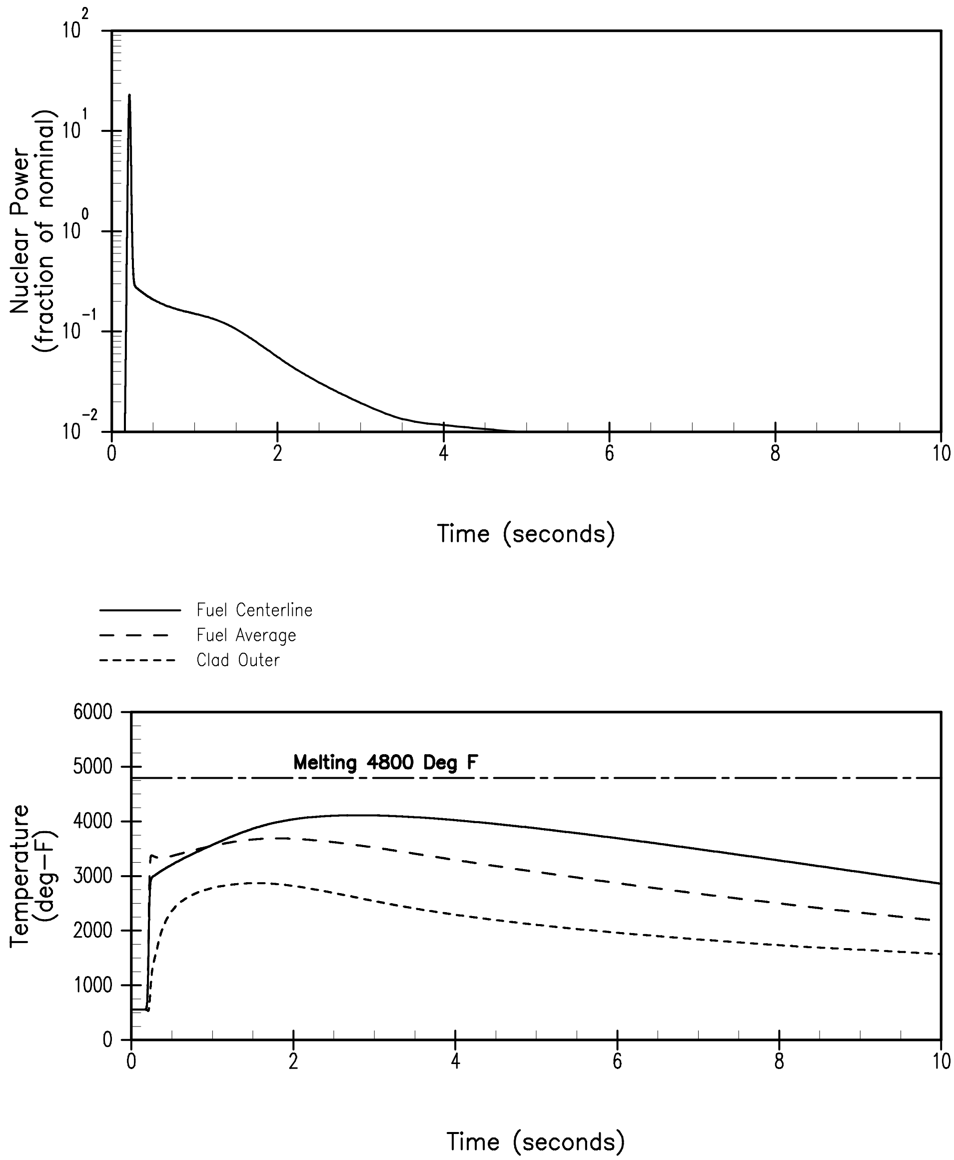
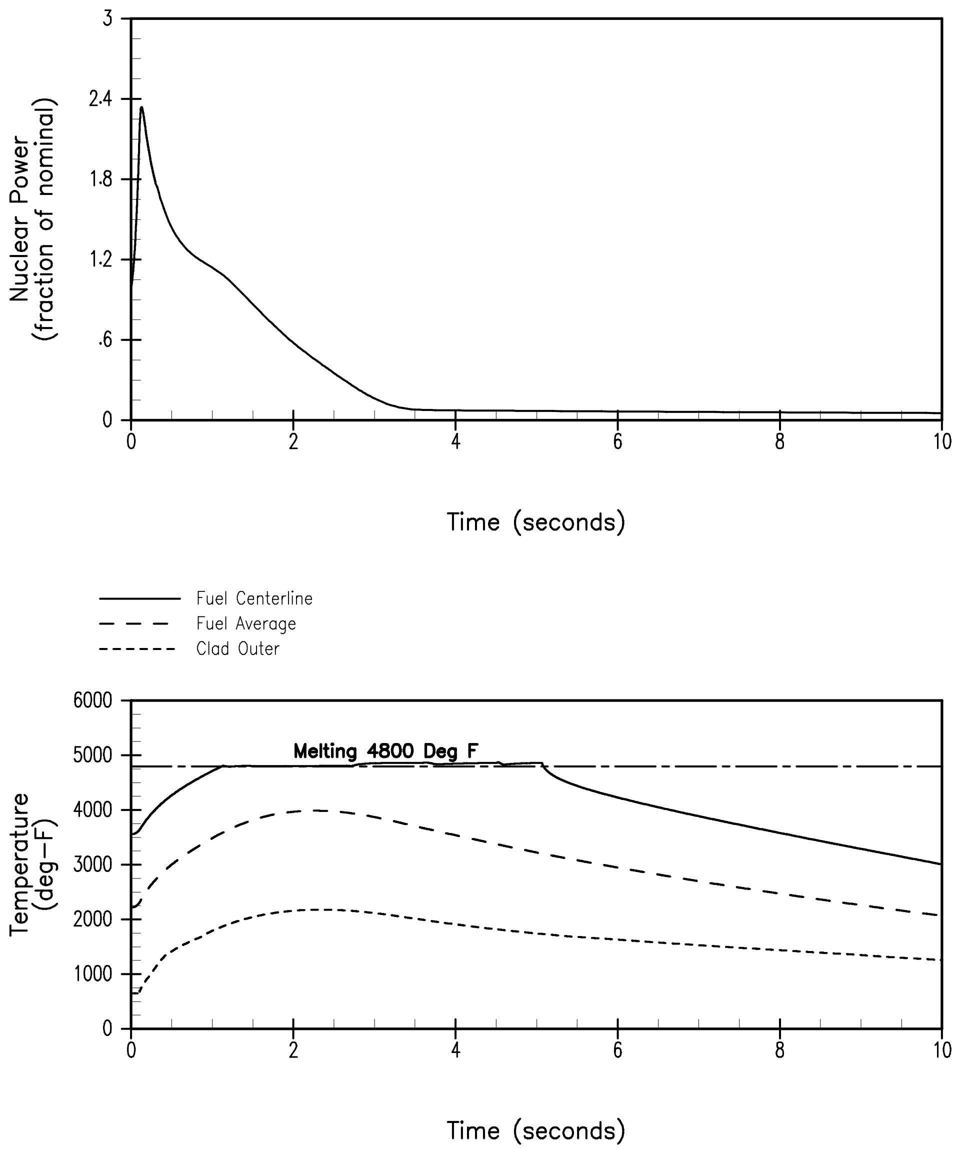


Figure 2.8.5.4.6-4
Rod Ejection – EOL/HFP Case



2.8.5.5 Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory

2.8.5.5.1 Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the boron concentration and temperature of the injected water and the response of the automatic control systems, a power level increase may result and, without adequate controls, could lead to fuel damage or overpressurization of the RCS. Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events.

The DNC review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses.

The acceptance criteria are based on:

- GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences
- GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences
- GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under normal operating conditions, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded

Specific review criteria are contained in the SRP, Section 15.5.1-2, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Section 15.5.1-2, Rev. 1.

As noted in FSAR Section 3.1 the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in FSAR Sections 3.1.1 and 3.1.2. The subject events are considered an ANS Condition II occurrence and are addressed by MPS3’s design and licensing basis.

Specifically, the adequacy of MPS3 safety related structures, systems and components with respect to nuclear design relative to conformance to:

- GDC-10, Reactor design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to:

  1. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These failures are within the capability of the plant clean up system to mitigate, and are consistent with plant design bases.

  2. Ensure return of the reactor to a safe shutdown state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

  3. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

  Note that the term “fuel damage” as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

  FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

  The analytical model used for MPS3 requires that the DNBR remains above the 95/95 DNBR limit at all times during the transient. FSAR Section 4.4.1.1 states in part that the Safety Analysis Limit (SAL) DNBR remains above the 95/95 value. Therefore, MPS3 meets the current licensing basis requirements regarding DNBR limits.

- GDC-15, Reactor Coolant System Design, is described in FSAR Section 3.1.2.15.

  It requires that the design pressure and temperature for each component in the reactor coolant and associated auxiliary, control and protection systems be selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

  Additionally, RCPB components achieve a large margin of safety by the use of proven ASME materials and design codes; the use of proven fabrication techniques; nondestructive shop testing; and integrated hydrostatic testing of assembled components. FSAR Chapter 5 discusses the RCS design.

- GDC-26, Reactivity Control System Redundancy and Capability, is described in FSAR Section 3.1.2.26.

  Two reactivity control systems are provided. They are the RCCAs and chemical shim (boric acid). The RCCAs are inserted into the core by the force of gravity.

  During operation the shutdown rod banks are fully withdrawn. The rod control system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specific fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses, and the most reactive rod cluster is assumed to be in the fully withdrawn position.

  The CVCS maintains the reactor in the cold shutdown state independent of the position of the control rods. It can compensate for xenon burnout transients.

  FSAR Chapter 4 presents details of the construction for the RCCAs. FSAR Chapter 7 discusses their operation. FSAR Chapter 9 describes the means of controlling boric acid concentration. FSAR Section 15.4.6 includes an analysis addressing the causes and consequences of the boron dilution event.

FSAR Sections 15.5.1 and 15.5.2 present the discussion and analyses of 1) inadvertent operation of the ECCS during power operation and 2) CVCS malfunction that increases reactor coolant inventory. The inadvertent operation of the ECCS during power operation event (flow from the charging pump) was considered to be bounding with respect to the CVCS malfunction that increases reactor coolant inventory event described in FSAR Section 15.5.2.

Westinghouse NSALs 02-3 Rev. 01; 02-4, Rev. 0; and 02-5 Rev 01 identified potential non-conservative errors in SG level measurement due to the pressure drop across the SG mid deck plate; potential impacts on the SG level reactor trip setpoints; and potential impacts to SG water level control system uncertainties utilized as initial condition assumptions for SG water level related safety analyses. DNC implemented modifications to the MPS3 narrow range SG level measurement instrument loops during 3R11 (April, 2007) to address changes in instrument uncertainties for level control and setpoints used for SG low-low level reactor trip.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.5.2 Technical Evaluation

2.8.5.5.2.1 Introduction

Inadvertent Operation of ECCS

The MPS3 ECCS design consists of both centrifugal charging pumps for flow delivery at high RCS pressures (i.e., design pressure of 2800 psig) and SI pumps for flow delivery at lower RCS pressures (i.e., design pressure of 1750 psig). Since the centrifugal charging pumps have the capability to deliver flow to the RCS at the prevailing RCS pressure, the “Inadvertent Operation of the ECCS during Power Operation” event has been analyzed as part of the accidents examined in FSAR Chapter 15.

The centrifugal charging pumps automatically start on receipt of a safety injection actuation signal (SIAS), align to take suction from the refueling water storage tank (RWST) and inject to the RCS cold legs and the RCP seals. As discussed in Section 1.0, as part of the SPU, a plant modification is being implemented to change the logic required for ECCS injection from the centrifugal charging pumps. The centrifugal charging pumps will continue to automatically start and take suction on the RWST upon receipt of an SIAS, but with the modification, automatic injection to the RCS cold legs will only occur when both SIS and the Cold Leg Injection Permissive signals are actuated. The Cold Leg Injection Permissive is activated when two of four low pressurizer pressure channels indicate less than 1900 psia. Therefore, the Inadvertent ECCS at Power event that has been analyzed for FSAR Section 15.5.1 no longer needs to consider flow from the centrifugal charging pumps to the RCS cold legs. The new limiting Inadvertent ECCS at Power scenario that needs to be considered is that with maximum RCP seal injection.

The analysis of the CVCS Malfunction that Increases Reactor Coolant Inventory event described in FSAR Section 15.5.2 is presented in the discussion of CVCS Malfunction below.

CVCS Malfunction

With the current plant configuration, the Inadvertent Operation of the ECCS during Power Operation event (i.e., with flow from the centrifugal charging pumps), as presented in FSAR Section 15.5.1, bounded any potential control system failure of the Chemical and Volume Control System. However, since flow from the centrifugal charging pumps is no longer the limiting scenario for the events presented in FSAR Section 15.5.1, a separate analysis has been performed for the CVCS Malfunction that Increases Reactor Coolant Inventory events discussed in FSAR Section 15.5.2.

Increases in reactor coolant inventory caused by a malfunction of the CVCS may be postulated to result from operator error or a control signal malfunction. Transients examined in this section are characterized by increasing pressurizer level, increasing pressurizer pressure, and a constant boron concentration. The transients analyzed in this section are done to demonstrate that there is adequate time for the operator to take corrective action to terminate the event prior to the integrity of the pressurizer safety valves (PSVs) being compromised (i.e., before water is relieved out of the PSVs as a result of a water-solid pressurizer condition). An increase in reactor coolant inventory, which results from the addition of cold, unborated water to the RCS, is analyzed in Section 2.8.5.4.5, Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant.

The most limiting case occurs if the charging system is in automatic control and the pressurizer level channel being used for charging control is assumed to fail in a low direction. This causes the maximum charging flow to be delivered to the RCS and letdown flow to be isolated. No credit is taken for the reactor trip on high pressurizer level. To prevent compromising the integrity of the PSVs, the operator must be relied upon to terminate the charging flow or confirm that the pressurizer PORV block valves are open so that pressure relief will be available from at least one pressurizer PORV.

2.8.5.5.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Inadvertent Operation of ECCS

The following key assumptions were made in the analysis:

- SPU NSSS power up to 3666 MWt plus 2 percent power uncertainty was assumed.
- The initial RCS average temperature was set to the nominal value minus a T_{avg} uncertainty of 4.0°F.
- The initial RCS pressure was 50 psid below its nominal value of 2250 psia to account for initial condition uncertainties.
- The initial pressurizer level was set to the nominal full power programmed value plus 7.6 percent span to account for initial condition uncertainties.
- Maximum feedback was assumed with a large (absolute value) negative moderator temperature coefficient and a most-negative Doppler power coefficient.
- The pressurizer heaters were assumed to be available to maximize the fluid expansion in the pressurizer.
- Normal letdown was assumed to be isolated coincident with event initiation.
- Reactor trip on the initiating SIS was assumed to occur coincident with event initiation.
- The PSVs were assumed to open at 2425 psia, corresponding to a pressure 3 percent below the nominal set-pressure of 2500 psia.

The inadvertent operation of the ECCS at power event is classified as an ANS Condition II occurrence. Condition II events are faults of moderate frequency.

The criteria established for Condition II events include the following.

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

Based on historical precedence and a detailed understanding of the transient conditions associated with this event, conditions do not approach the core thermal DNB limits as the core power, RCS pressure and RCS temperatures remain relatively unchanged. Therefore, the DNBR typically increases and does not approach the DNBR safety analysis limit following event initiation. For this reason, it is not necessary to calculate a minimum DNBR value for this event.

To address the third criterion of not creating a more serious plant condition, an analysis is performed to demonstrate that there is more than sufficient time for the operators to respond to the event and terminate the RCS inventory addition or to confirm that the pressurizer PORV block valves are open so that pressure relief will be available from at least one pressurizer PORV prior to the integrity of the PSVs being compromised (i.e., before water is relieved out of the PSVs as a result of a water-solid pressurizer condition).

Therefore, this event is analyzed to determine the minimum time from event initiation to the time at which the integrity of the PSVs would be compromised.

CVCS Malfunction

The assumptions and acceptance criteria for this analysis are the same as those discussed above, except no reactor trip was assumed. In addition, the maximum charging system flow, based on the RCS back pressure, is assumed to be delivered to the RCS. Cases are examined with flow from both one and two centrifugal charging pumps to determine the time available for the operators to take the necessary corrective actions to prevent compromising the integrity of the PSVs. The charging flow is assumed to have the same boron concentration as the RCS.

2.8.5.5.2.3 Description of Analyses and Evaluations

Inadvertent Operation of ECCS

The transient response associated with this event was calculated by a detailed digital simulation of the plant. The transient response is modeled assuming the maximum RCP seal injection flow coincident with the isolation of the letdown flow path. The analysis was performed using the RETRAN code (Reference 1), which simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. The code computed pertinent plant variables including temperatures, pressures, and power levels.

CVCS Malfunction

The transient response for the CVCS malfunction was calculated by a detailed digital simulation of the plant. The transient response is modeled assuming the maximum charging flow coincident with the isolation of the letdown flow path. The analysis was performed using the RETRAN code (Reference 1), which simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. The code computed pertinent plant variables including temperatures, pressures, and power levels.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory analyses. As stated in Section 2.8.5.5.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.5.2.4 Results

Inadvertent Operation of ECCS

The pressurizer level increases throughout the transient as a result of the seal injection flow. At approximately 5.3 minutes into the transient, the pressurizer backup heaters are actuated on a high pressurizer water level deviation signal. The pressurizer reaches a water-solid condition at approximately 30.4 minutes following event initiation, with the PSVs opening (if the PORVs are unavailable) at 70.4 minutes. If available, one PORV has sufficient capacity to preclude actuation of the PSVs.

Since the transient conditions remain relatively unchanged following event initiation, the minimum DNBR is never less than the initial value. Thus, there is no cladding damage and no release of fission products to the RCS.

With respect to not creating a more serious plant condition, water relief out of the PSVs due to a water-solid pressurizer would occur at a time which is much longer than the time required for the operators to respond to the event and to terminate the RCS inventory addition and restore letdown or to confirm that the pressurizer PORV block valves are open so that pressure relief will be available from at least one pressurizer PORV.

CVCS Malfunction

The transient responses for the limiting CVCS system malfunction cases are shown in Figures 2.8.5.5-1 and 2.8.5.5-2. Table 2.8.5.5-1 shows the calculated sequence of events. In all the cases analyzed, core power and RCS temperatures remain relatively constant.

The pressurizer level increases throughout the transient as a result of the injected flow. The pressurizer backup heaters are actuated on a high pressurizer water level deviation signal. In the case with one pump operating, the pressurizer reaches a water-solid condition at approximately 12.7 minutes following event initiation, with the PSVs opening (if the PORVs are unavailable) at 19.3 minutes. In the case with two pumps operating, the pressurizer reaches a water-solid condition at approximately 8.4 minutes following event initiation, with the PSVs opening (if the PORVs are unavailable) at 10.0 minutes. If available, one PORV has sufficient capacity to preclude actuation of the PSVs.

The results show none of the transient conditions during the event approach the core thermal DNB limits. With respect to not creating a more serious plant condition, water relief out of the PSVs due to a water-solid pressurizer would occur at a time which is longer than the time required for the operators to respond to the event and to terminate the RCS inventory addition or to confirm that the pressurizer PORV block valves are open so that pressure relief will be available from at least one pressurizer PORV. The sequence of events presented in Table 2.8.5.5-1 shows that the operators have sufficient time to take corrective action.

At the same time the failure of the pressurizer level channel occurs, a number of main control board alarms will be generated, including the following:

- Pressurizer Level Deviation
- Pressurizer Level Low Heater Off and Letdown Secure

- Pressurizer heater Backup Group Auto Trip
- Pressurizer heater Control Group Auto Trip

Upon receipt of these alarms, the operators will be alerted to take manual control of charging flow to prevent pressurizer overfill. Guidance is provided in plant procedures to defeat the failed channel and restore automatic letdown and charging control to one of the two operable channels and terminate the event. This type of malfunction is routinely included in the operator simulator training and this operator training provides assurance the operator action to terminate the overfill will occur within the required time frame.

2.8.5.5.3 Conclusion

DNC has reviewed the analyses of the inadvertent operation of ECCS and CVCS event and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. DNC further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, DNC concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the inadvertent operation of ECCS and CVCS event.

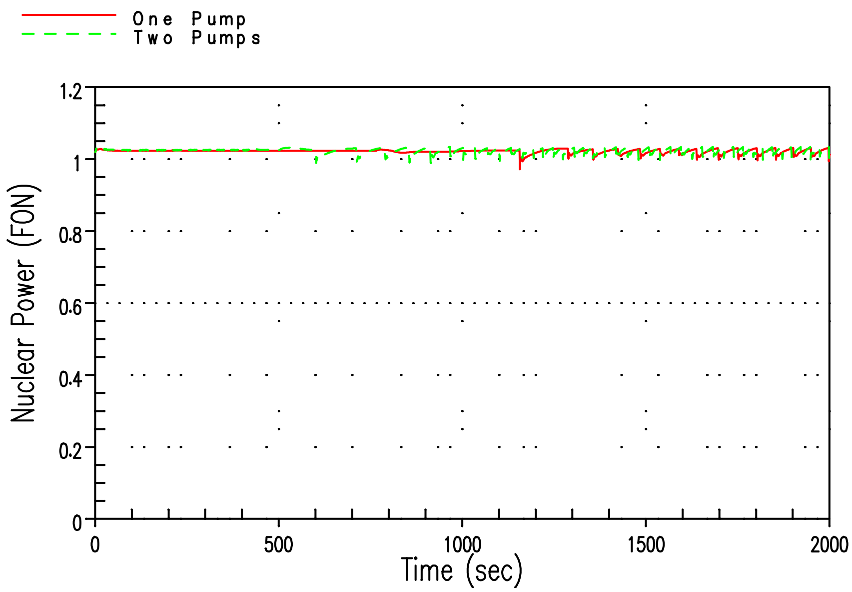
2.8.5.5.4 References

1. WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, April 1999.

Table 2.8.5.5-1
Time Sequence of Events – CVCS Malfunction that Increases Reactor Coolant Inventory

Case	Event	Time (sec)
CVCS malfunction, One pump operating	Maximum charging flow initiated/letdown isolated	0.0
	Pressurizer heater actuation on high pressurizer level deviation signal	117.3
	Pressurizer reaches water-solid condition	761.0
	Pressurizer safety valve setpoint reached	1156.2
CVCS malfunction, Two pumps operating	Maximum charging flow initiated/letdown isolated	0.0
	Pressurizer heater actuation on high pressurizer level deviation signal	78.6
	Pressurizer reaches water-solid condition	503.0
	Pressurizer safety valve setpoint reached	601.4

Figure 2.8.5.5-1
CVCS Malfunction that Increases Reactor Coolant Inventory, Nuclear Power and Vessel Average Temperature vs. Time



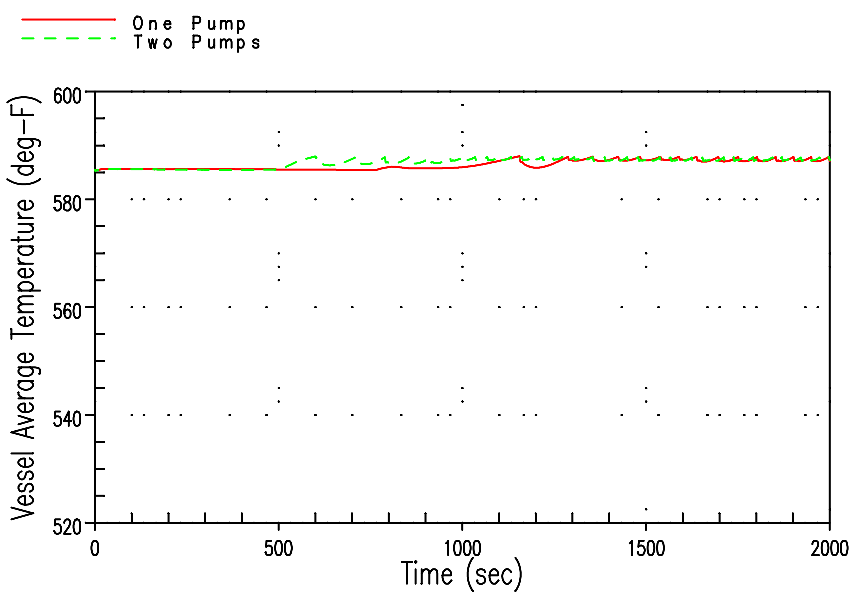
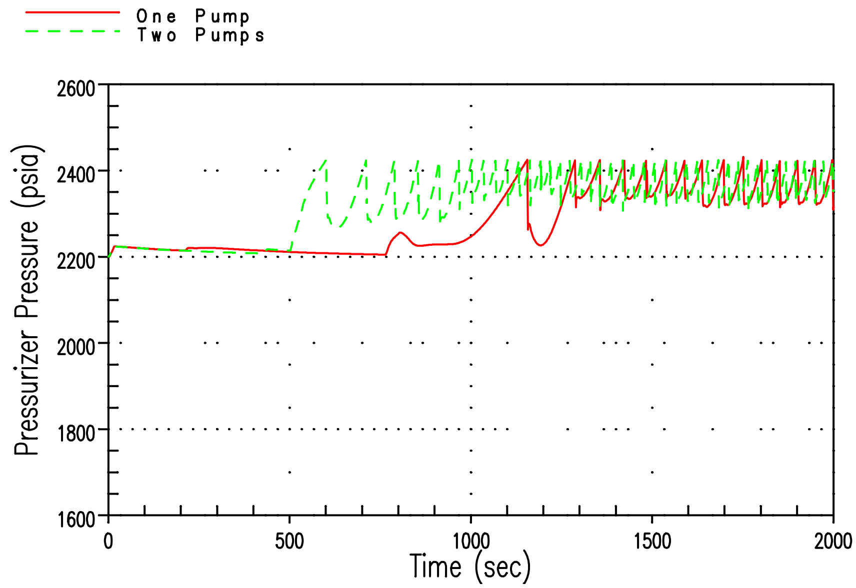
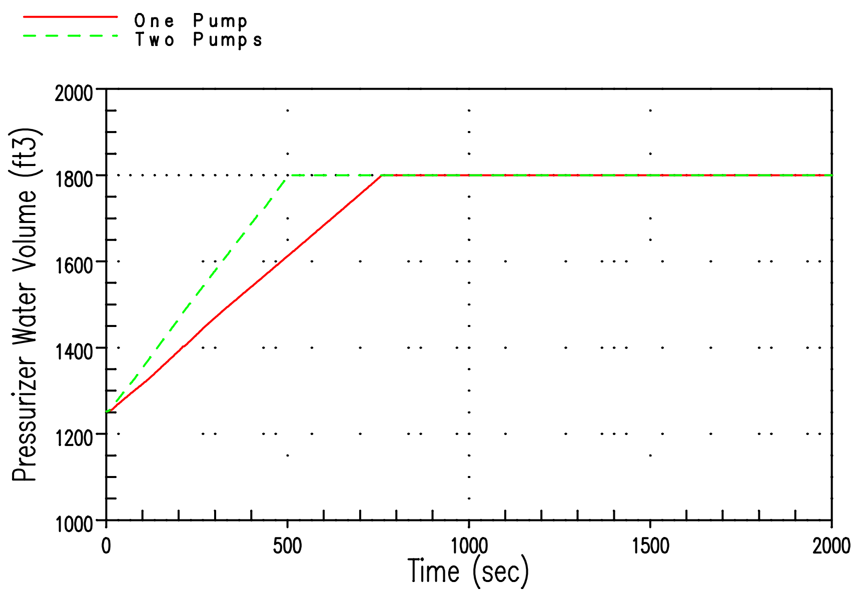


Figure 2.8.5.5-2
CVCS Malfunction that Increases Reactor Coolant Inventory, Pressurizer Pressure and Pressurizer Water Volume vs. Time





2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Pressurizer Pressure Relief Valve Opening

2.8.5.6.1.1 Regulatory Evaluation

The inadvertent opening of a pressure relief valve results in a reactor coolant inventory decrease and a decrease in reactor coolant system pressure. A reactor trip normally occurs due to low reactor coolant system pressure. The DNC review covered

- The sequence of events
- The analytical model used for analyses
- The values of parameters used in the analytical model
- The results of the transient analyses

The acceptance criteria are based on

- GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during normal operations, including anticipated operational occurrences.
- GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.
- GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under normal conditions of operation, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded.

Specific review criteria are contained in SRP, Section 15.6.1, and other guidance provided in Matrix 8 of RS-001.

Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800), SRP Section 15.6.1, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2. The subject event is considered a Condition II occurrence in the FSAR Section 15.0.1.2.

Specifically, the adequacy of MPS3 design relative to conformance to

- GDC-10, Reactor Design, is described in FSAR Section 3.1.2.10.

  The reactor core and associated coolant, control and protection systems are designed with adequate margins to

  2. Assure that fuel damage is not expected during normal core operation and operational transients (Condition I) or any transient conditions arising from occurrences of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These are within the capability of the plant clean up system to mitigate, and are consistent with plant design bases.

  3. Ensure return of the reactor to a safe shutdown state following infrequent incident (Condition III) events with only a small fraction of fuel rods damaged, although sufficient fuel damage might occur to preclude immediate resumption of operation.

  4. Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

  Note that the term “fuel damage” as used in Item 1 above is defined as penetration of the fission product barrier (i.e., the fuel rod clad). Also note that ANSI N18.2-73 expands the definitions of the four conditions enumerated in Items 1 through 3 above.

  FSAR Chapter 4 discusses the design bases and the design evaluation of reactor components. FSAR Chapter 7 provides the details of the control and protections systems instrumentation design and logic. This information supports the FSAR Chapter 15 accident analysis, which shows that acceptable fuel design limits are not exceeded for Condition I and II occurrences.

- GDC-15, Reactor Coolant System Design, is described in FSAR Section 3.1.2.15. The design pressure and temperature for each component in the reactor coolant and associated auxiliary, control, and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

- GDC-26, Reactor Coolant System Redundancy and Capability, is described in FSAR Section 3.1.2.26. Two reactivity control systems are provided. These are the RCCAs and chemical shim (boric acid). The RCCAs are inserted into the core by the force of gravity.

  During operation, the shutdown rod banks are fully withdrawn. The rod control system automatically maintains a programmed average reactor temperature, compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specific fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses, and the most reactive rod cluster is assumed to be in the fully withdrawn position.

  The CVCS maintains the reactor in the cold shutdown state independent of the position of the control rods. It can compensate for xenon burnout transients.

FSAR Chapter 4 presents details of the construction for the RCCAs. FSAR Chapter 7 discusses their operation. FSAR Chapter 9 describes the means of controlling boric acid concentration. FSAR Chapter 15 includes performance analyses under accident conditions.

FSAR Section 15.6.1 states that an accidental depressurization of RCS could occur as result of an inadvertent opening of a pressurizer relief or safety valve. Since a safety valve is sized to relieve approximately twice the steam flow rate of a relief valve, and therefore allows a much more rapid depressurization upon opening, the most severe core conditions are associated with an inadvertent opening of a pressurizer safety valve. Initially, the event results in rapidly decreasing RCS pressure, which could reach the hot leg saturation pressure without reactor protection system intervention. The pressure continues to decrease throughout the transient. With a positive moderator temperature coefficient, the effect of the pressure decrease would be to increase power via the moderator density feedback, but the rod control system (if in automatic mode) functions to maintain the power essentially constant throughout the initial stage of the transient. The average coolant temperature decreases slowly, but the pressurizer level increases until reactor trip.

FSAR Section 15.6.1.2 states the transient is analyzed utilizing the LOFTRAN code. Initial operating conditions are assumed at values consistent with steady state operations. Plant characteristics and initial conditions are discussed in FSAR Section 15.0.3. FSAR Section 15.6.1.3 concludes that the results of the analysis show that the pressurizer low pressure and the overtemperature DT reactor protection system signals provide adequate protection against the RCS depressurization event. The DNBR remains above the limit value throughout the transient. Therefore, the DNBR design basis as described in FSAR Section 4.4 is met.

NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, defines the scope of License Renewal. Specific design transient analyses are not within the scope of License Renewal.

2.8.5.6.1.2 Technical Evaluation

2.8.5.6.1.2.1 Introduction

An accidental depressurization of the RCS could occur as a result of an inadvertent opening of a pressurizer relief valve. To conservatively bound this scenario, the Westinghouse methodology models the failure of a pressurizer safety valve since a safety valve is sized to relieve approximately twice the steam flow than a relief valve and will allow a much more rapid depressurization upon opening. The depressurization resulting from an open safety valve is also much more rapid than would occur from the accidental actuation of pressurizer spray. Therefore, the failure of a pressurizer safety valve yields the most severe core conditions resulting from an accidental depressurization of the RCS. A stuck open safety valve is considered to be a small break LOCA during which the RCS cannot be isolated, whereas the failure of a PORV can be overridden by the closure of the block valve. Nonetheless, the results of this analysis are shown to comply with the acceptance criteria for an event of moderate frequency.

Initially, the event results in a rapidly decreasing RCS pressure, which could reach hot-leg saturation conditions without reactor protection system intervention. If saturated conditions are reached, the rate of depressurization is slowed considerably. However, the pressure continues to decrease throughout the event. The power remains essentially constant throughout the initial stages of the transient.

The reactor may be tripped by the following reactor protection system signals:

- Low pressurizer pressure
- Overtemperature T

2.8.5.6.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

To produce conservative results in calculating the DNBR during the transient, the following assumptions were made:

- The accident was analyzed using the Revised Thermal Design Procedure (Reference 1). Initial core power, RCS pressure, and RCS temperature were assumed to be at their nominal values, consistent with steady-state full-power operation. Minimum measured flow was modeled. Uncertainties in initial conditions were included in the DNBR limit as described in Reference 1. The initial core power level assumed is 3650 MWt.
- A zero moderator coefficient of reactivity was assumed. This is conservative for beginning-of-life (BOL) operation in order to provide a conservatively low amount of negative reactivity feedback due to changes in moderator temperature.
- A small (absolute value) Doppler coefficient of reactivity is assumed, such that the resultant amount of negative feedback is conservatively low in order to maximize any power increase due to moderator feedback.
- The spatial effect of voids resulting from local or subcooled boiling was not considered in the analysis with respect to reactivity feedback or core power shape. In fact, it should be noted, the power peaking factors constant at their design values, while the void formation and resulting core feedback effects in considerable flattening of the power distribution. Although this would significantly increase the calculated DNBR, no credit was taken for this effect.
- The analysis performed assumes that the rod control system is in automatic. However, no rod motion occurs during the transient because the conditions do not change enough to demand any rod motion from the rod control system. Thus, the transient results are identical with or without automatic rod control.

Based on its frequency of occurrence, the accidental depressurization of the RCS accident was considered a Condition II event as defined by the American Nuclear Society. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux should not be exceeded. This was met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design pressures. Note that since this event is a depressurization event, these limits are not challenged. Both primary and secondary pressures decrease for the entire duration of the event.

2.8.5.6.1.2.3 Description of Analyses and Evaluations

The purpose of this analysis was to demonstrate that the reactor protection system functions and mitigates the consequences of the RCS depressurization event. This analysis is concerned with the transient from initiation through just past the time of reactor trip. With respect to long term post-accident recovery, it is assumed that operators follow approved plant procedures to bring the plant to a safe post-accident condition.

The accident was analyzed by using the detailed digital computer code RETRAN (Reference 2). This code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal Application for the impact on the Inadvertent Pressurizer Pressure Relief Valve Opening. As stated in Section 2.8.5.6.1.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.6.1.2.4 Results

The system response to an inadvertent opening of a pressurizer safety valve is shown in Figure 2.8.5-1 through 2.8.5-4. Figure 2.8.5-1 illustrates the nuclear power transient following the depressurization. Nuclear power remains essentially unchanged until the reactor trip occurs on overtemperature ΔT (OTΔT). The pressurizer pressure transient is illustrated in Figure 2.8.5-2. Pressure decreases continuously throughout the transient; however, pressure decreases more rapidly after core heat generation is reduced via the reactor trip. If the saturation temperature is reached in the hot leg, the pressure decrease slows. Illustrated in Figure 2.8.5-3 is the loop average temperature transient. The loop average temperature decreases slowly until the reactor trip occurs. The DNBR decreases initially, but increases rapidly following the reactor trip, as demonstrated in Figure 2.8.5-4. The DNBR remains above the limit value of 1.60 throughout the transient.

The calculated sequence of events is shown in Table 2.8.5.6.1-1. The calculated minimum DNBR is provided in Table 2.8.5.6.1-2 along with the calculated minimum DNBR from the previous licensing basis analysis. Note that a comparison of the previous and SPU DNBR results is difficult because different DNB correlations and different fuel are involved. The previous results are based on the WRB-2 correlation with 17x17 Vantage 5H fuel and the SPU analyses utilize the WRB-2M correlation (Reference 3) with 17x17 RFA fuel. Also, the previous analyses applied a large penalty (16.5 percent) on the calculated DNBRs due to rotated IFM grids for 17x17 Vantage 5H fuel. The WRB-2M correlation results in higher calculated DNBRs compared to the WRB-2 correlation, and the introduction of 17x17 RFA fuel eliminates the rotated grid DNBR penalty.

The results of the analysis show that the OTΔT reactor protection system function provides adequate protection against the RCS depressurization event since the minimum DNBR remains above the safety analysis limit throughout the transient. Therefore, no cladding damage or release of fission products to the RCS is predicted for this event.

The results of the analysis performed for the accidental depressurization of the RCS for the NSSS power of 3666 MWt support the implementation of the stretch power uprate at MPS3.

2.8.5.6.1.3 Conclusion

DNC has reviewed the analysis of the inadvertent opening of a pressurizer pressure relief valve event and concludes that the analysis has adequately accounted for plant operation at the uprated power level and was performed using acceptable analytical models. DNC further concludes that the evaluation has demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits and the reactor coolant pressure boundary pressure limits will not be exceeded as a result of this event. Based on this, DNC concludes that the plant will continue to meet the MPS3 current licensing basis requirements with respect to GDCs -10, -15, and -26 following implementation of the Stretch Power Uprate. Therefore, DNC finds the Stretch Power Uprate acceptable with respect to the inadvertent opening of a pressurizer pressure relief valve event.

2.8.5.6.1.3.1 References

1. WCAP-11397-P-A, Revised Thermal Design Procedure, A. J. Friedland and S. Ray, April 1989.

2. WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor NON-LOCA Safety Analyses, April 1999.

3. WCAP-15025-P-A, Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17X17 Rod Bundles with Modified LPD Mixing Vane Grids, April 1999.

Table 2.8.5.6.1-1
Time Sequence of Events – Accidental Depressurization of the RCS

Event	Time (sec)
Inadvertent opening of one Pressurizer Safety Valve	0.0
OTΔT reactor trip setpoint reached	40.4
Rods begin to drop	41.9
Minimum DNBR occurs	42.5

Table 2.8.5.6.1-2
Accidental Depressurization of the RCS – SPU and Previous Analysis Results

Event	Minimum DNBR	DNBR Safety Analysis Limit
Stretch Power Uprate Analysis	1.874	1.60
Previous Licensing Basis Analysis	1.584	1.37

Figure 2.8.5-1 RCS Depressurization Nuclear Power vs. Time

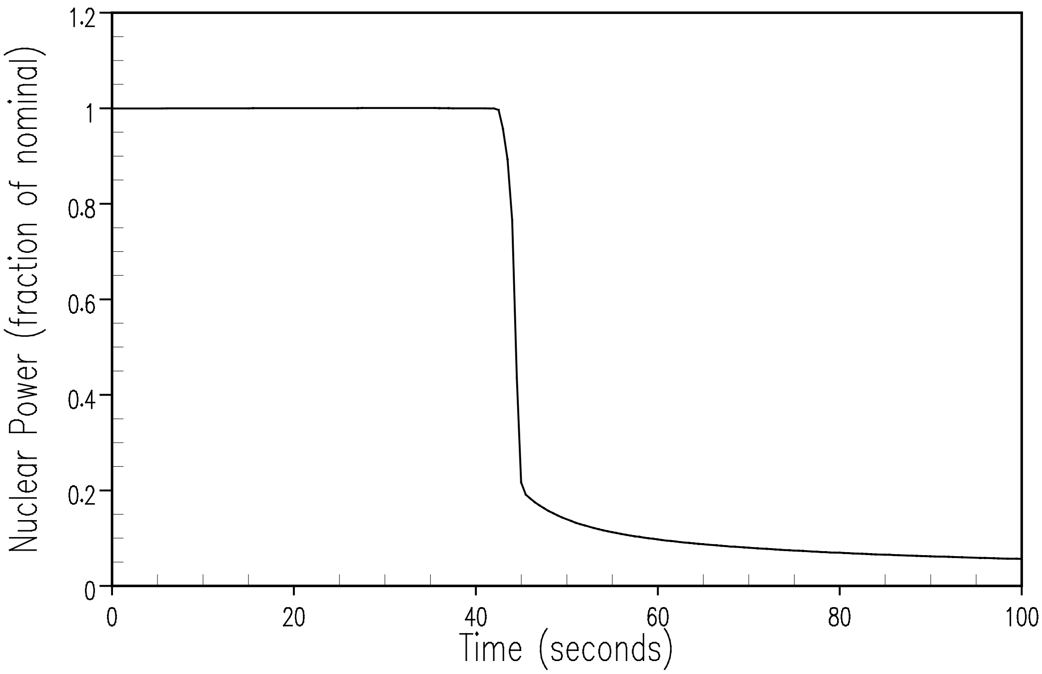


Figure 2.8.5-2 RCS Depressurization Pressurizer Pressure vs. Time

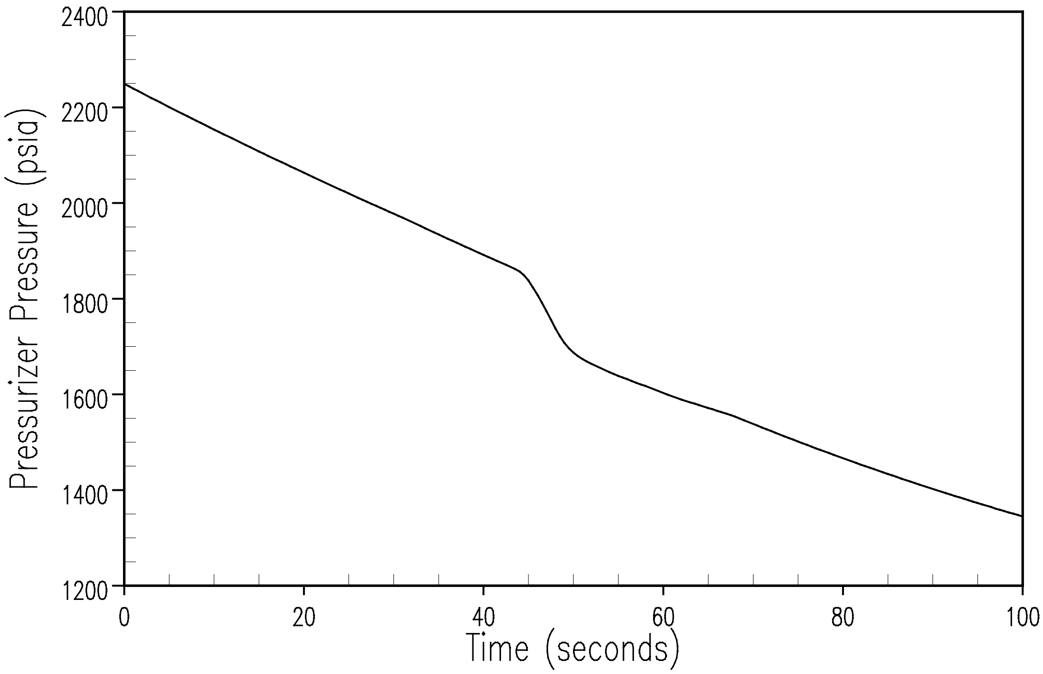


Figure 2.8.5-3 RCS Depressurization Indicated Loop Average Temperature vs. Time

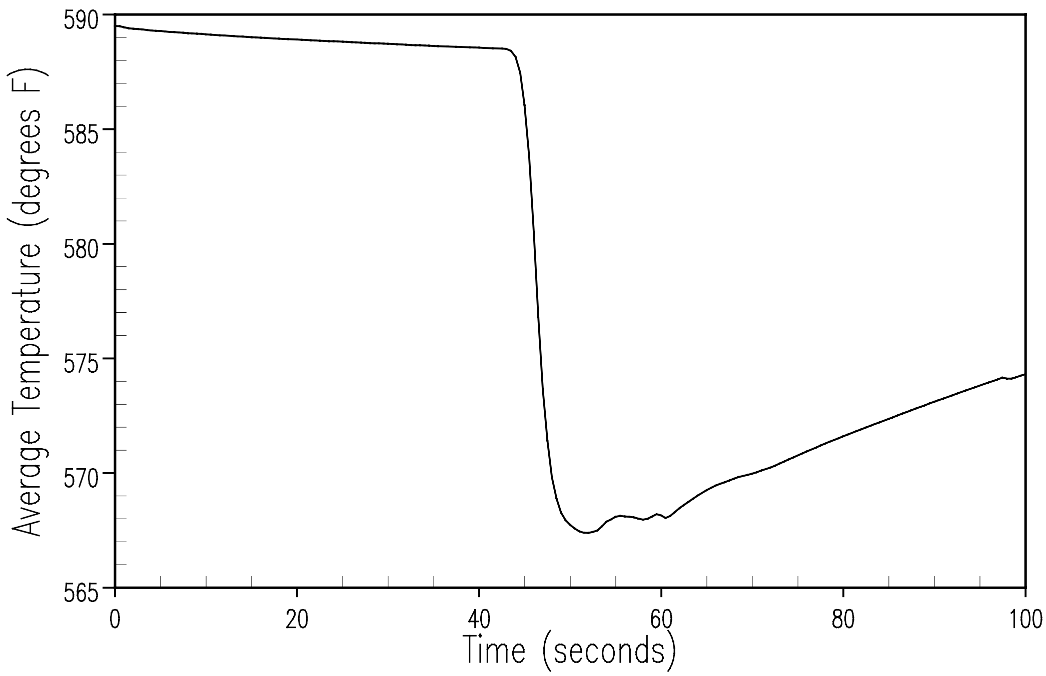
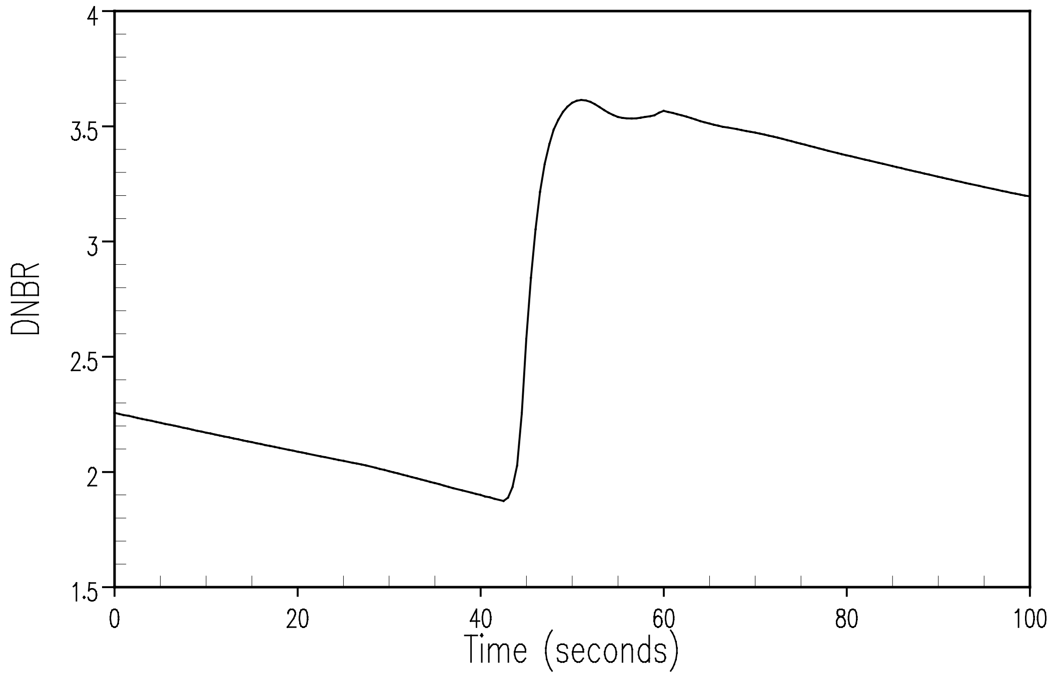


Figure 2.8.5-4 RCS Depressurization DNBR vs. Time



2.8.5.6.2 Steam Generator Tube Rupture

2.8.5.6.2.1 Regulatory Evaluation

A steam-generator-tube-rupture (SGTR) event causes a direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and main steam safety valves (MSSVs) or atmospheric dump (relief) valves (ADVs). Reactor protection and ESFs are actuated to mitigate the accident, and operator action is taken to isolate the impacted SG and restrict the doses to within the requirements of 10 CFR 50.67 and SRP Section 15.0.1. The DNC review covered:

- The postulated initial core and plant conditions,
- The method of thermal-hydraulic analysis
- The sequence of events (assuming offsite power either available or unavailable)
- The assumed reactions of reactor system components,
- The functional and operational characteristics of the reactor protection system
- The operator actions consistent with the plant's emergency operating procedures
- The results of the accident analysis

A single failure of a mitigating system is assumed for this event.

The DNC review of the SGTR focused on the thermal and hydraulic analyses for the SGTR in order to:

- Determine whether 10 CFR 50.67 is satisfied with respect to radiological consequences, which are discussed in Section 2.9.2.
- Confirm that the faulted SG does not experience an overfill. Preventing SG overfill is necessary in order to prevent the release of water to the environment through either the MSSVs or the ADVs and to preclude the failure of main steam lines.

Specific review criteria are contained in SRP Section 15.6.3, Rev. 2 and other guidance provided in Matrix 8 of RS-001, Revision 0. Since MPS3 has obtained approval to use the Alternate Source Term (AST) methodology to calculate dose, the acceptance criteria for SRP Section 15.0.1, Rev. 0, apply, and supersede those provided in SRP Section 15.6.3, Rev. 2.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Sections 15.6.3, Rev. 2. Since MPS3 has obtained approval to use the AST methodology to calculate dose, the acceptance criteria for SRP Section 15.0.1, Rev. 0, apply, and supersede those provided in SRP Section 15.6.3, Rev. 2.

As noted in the FSAR Section 15.6.3, “Steam Generator Tube Rupture,” the SGTR accident analysis includes analyses performed to demonstrate margin-to-overfill and analyses to ensure that possible radiological dose consequences are within allowable guidelines. The dose analysis requires that thermal-hydraulic calculations be performed to determine the amount of reactor coolant discharged to the ruptured steam generator and the amounts of steam released from the steam generators (see FSAR Section 15.6.3.2.2). The accident examined is the complete severance of a single steam generator tube. This event is considered an ANS Condition IV event.

The SGTR analysis was performed for MPS3 using the methodology developed in WCAP-10698 and Supplement 1 to WCAP-10698 (FSAR 15.6.3.2.1). This analysis methodology was developed by the SGTR Subgroup of the WOG and was approved by the NRC in Safety Evaluation Reports dated March 30, 1987, and December 17, 1985. The LOFTTR2 program, an updated version of the LOFTTR1 program, was used to perform the SGTR analysis for MPS3.

FSAR Section 15.6.3.2.1 concludes that the ruptured steam generator does not experience an overfill condition.

In a letter dated September 15, 2006, from Victor Nerses, NRC, to David Christian, DNC, "Millstone Power Station, Unit No. 3 - Issuance of Amendment RE: Alternate Source Term," the NRC has given DNC approval to implement the alternate source term dose calculation methodology at MPS3. With the implementation of this License Amendment, the dose criteria in 10 CFR 50.67 are the licensing basis for all subsequent radiological consequences analyses. As stated in the NRC's SER, the radiological consequences for the SGTR are within the dose guidelines provided in 10 CFR 50.67 and accident dose criteria specified in SRP Section 15.0.1.

Westinghouse NSALs 02-3 Rev. 01; 02-4, Rev. 0; and 02-5 Rev 01 identified potential non-conservative errors in SG level measurement due to the pressure drop across the SG mid deck plate; potential impacts on the SG level reactor trip setpoints; and potential impacts to SG water level control system uncertainties utilized as initial condition assumptions for SG water level related safety analyses. DNC implemented modifications to the MPS3 narrow range SG level measurement instrument loops during 3R11 (April, 2007) to address changes in instrument uncertainties for level control and setpoints used for SG low-low level reactor trip.

NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3," dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.6.2.2 Technical Evaluation

The evaluation of the design basis SGTR event demonstrated that the current design is acceptable to support the SPU operation.

2.8.5.6.2.2.1 Introduction

The SGTR analysis is described in FSAR, Section 15.6.3, "Steam Generator Tube Failure." The SGTR accident was analyzed to demonstrate margin-to-overfill and to ensure that possible radiological dose consequences are within allowable guidelines. The dose analysis required thermal-hydraulic calculations be performed to determine the amount of reactor coolant discharged to the ruptured steam generator, and the amounts of steam released from the steam generators. The effects of limiting single failures and the times for required operator actions were explicitly included in the analyses. Typically, it is not known beforehand which end of the average temperature (T_{avg}) window and steam generator tube plugging conditions give the bounding result for each type of analysis considered. Therefore, multiple cases were analyzed separately for the margin-to-overfill and mass-release analyses. Only the results of the limiting margin-to-overfill and mass-release cases are presented in the FSAR. The SPU analyses were performed using the methodology employed in the FSAR. Consistent with this methodology all cases were analyzed with a loss-of-offsite power.

The analysis included an analyzed NSSS power level of 3666 MWt plus 2 percent calorimetric uncertainty, and a full-power T_{avg} operating range from 581.5° to 589.5°F with an end-of-cycle 10°F T_{avg} coastdown, up to 10 percent steam generator tube plugging, and a main feedwater temperature range from 390° to 445.3°F. Multiple cases were analyzed separately for the margin-to-overfill and mass-release analyses to consider the range of T_{avg}, tube plugging, and initial secondary mass. In the SPU analyses, AFW isolation to the ruptured steam generator is assumed to occur when SG level reaches 30 percent narrow range level. The current analysis assumption was that AFW to the ruptured SG was assumed when level reached 29 percent narrow range level or at 16.5 minutes, whichever is longer. Because of the requirements of the SGTR EOP and the training emphasis on isolating the ruptured SG, operator training experience has consistently shown that the operator will isolate the ruptured SG before SG level reaches 30 percent (29 percent rounded up). Further, an analysis assumption where isolation is based on level is in keeping with the symptom-based EOP philosophy and the expected operator response rather than an arbitrarily selected time duration. The application of an arbitrarily selected time frame is unnecessary to assure operator action within the assumed time frame of the SGTR analysis.

The margin-to-overfill transient was analyzed until the ruptured steam generator secondary side and RCS pressures equalized, at which time the ruptured tube flow was considered isolated.

Sensitivity analyses were performed to determine the most limiting set of analysis conditions for the margin to overfill transient. Initial RCS average temperature, SG tube plugging, initial secondary water mass, FW temperature, and AFW flow were the parameters considered. The sensitivity analysis was necessitated by the modified ruptured SG isolation criteria being applied. The most limiting case models low T_{avg} (571.5°F including consideration of the end-of-cycle coastdown), 10 percent tube plugging, maximum FW temperature, low initial secondary water mass, and maximum AFW flow.

The mass-release cases determine the primary-to-secondary break flows and steam releases for the SGTR radiological consequences analysis. These cases are analyzed through tube rupture flow isolation and cooldown to RHRS in-service conditions to obtain the total steam releases from the intact and ruptured steam generators.

Sensitivity analyses were performed to determine the most limiting set of analysis conditions for the mass-release transient. Initial RCS average temperature, SG tube plugging, initial secondary water mass, FW temperature, and AFW flow were the parameters considered. The sensitivity analysis was necessitated by the updated ruptured SG isolation criteria being applied. The most limiting case models low T_{avg} (571.5°F including consideration of the end-of-cycle coastdown), 0 percent tube plugging, minimum FW temperature, high initial secondary mass, and maximum AFW flow.

Only the results of the limiting margin-to-overfill and mass-release cases are presented.

The radiological consequences analysis is presented in Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms.

2.8.5.6.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Design Basis Accident

The accident modeled is a double-ended break (0.002016 ft^2) of one steam generator tube located at the top of the tube sheet on the outlet-cold-leg-side of the steam generator. The location of the break on the cold side of the steam generator results in higher primary-to-secondary leakage than a break on the hot side of the steam generator. However, the break flow flashing fraction was conservatively calculated for use in the radiological consequences analysis assuming that all of the break flow came from the hot-leg side of the steam generator. The combination of these conservative assumptions regarding the break location results in a conservative calculation of the radiological consequences. It was also assumed that loss-of-offsite power occurred at the time of reactor trip, and the highest worth control assembly was assumed to be stuck in its fully withdrawn position at reactor trip. As discussed below, this is conservative for offsite releases because the SG initial mass is increased to account for the turbine runback that can occur prior to trip. If loss of offsite power was assumed at break initiation, the SG initial mass would be lower and, consequently, the offsite releases would be lower. Due to the assumed loss-of-offsite power, the condenser was not available for steam releases once the reactor was tripped. Consequently, after reactor trip, steam was released to the atmosphere through the steam generator MSPRVs.

Single Failure Considerations

The effects of single failures in margin-to-overfill and mass-release analyses were investigated in WCAP-10698 and its Supplement 1 (References 1 and 2). The limiting single failures for the MPS3 SGTR analyses are described below.

The limiting single failure for margin-to-overfill considerations is an electrical failure that results in the inability to open the MSPRBVs on two of the intact SGs. This results in two of the intact SGs being unavailable for the cooldown. Due to this failure, the cooldown is performed using only one intact SG.

The limiting single failure for the mass-release analysis for MPS3 is the MSPRV on the ruptured steam generator failing in the full open position. The MSPRV is an air operated valve used to automatically control SG pressure. Since the MSPRBV is a motor operated manual valve, it is not subject to a failed-open failure mode. It is assumed that the operator will mitigate the failed open valve by closing the Main Steam Pressure Relief Valve Isolation Valve which isolates the pathway to both the MSPRV and the MSPRBV. The cooldown is performed with all three intact steam generators' MSPRBVs.

Operator Actions Assumed

Important operator actions in the WOG Emergency Response E-3 Guidelines were explicitly modeled in the analysis. These actions were intended to terminate flow through the SGTR before proceeding to long-term cooldown. The operator actions modeled in the SPU analysis were consistent with those currently incorporated in the analyses presented in FSAR Section 15.6.3. However, the associated times were modified in conjunction with the SPU program.

The times required to perform the major recovery actions modeled in the SGTR analyses performed for the SPU were modified compared to those included in FSAR Section 15.6.3. These action times consisted of two components: initiation times (for the operator to start actions) and plant/system response times (for the plant conditions to reach performance objectives such as temperature, pressure, flow, etc., required by the recovery action). The latter times were determined from the thermal-hydraulic transient analyses of the SGTR accident. The operator action times are summarized in Table 2.8.5.6.2-1.

The operator actions that were modeled include:

Identifying the ruptured steam generator.

> Several means are available to the operator. The predominant indications are an unexpected rapid increase in the ruptured steam generator's narrow range level following the reactor trip, high radiation from a steam generator blowdown radiation monitor, or high radiation from a steam line radiation monitor.

Isolating the steam flow from the ruptured steam generator and throttling auxiliary feedwater flow to the ruptured steam generator.

> Isolating the ruptured steam generator minimizes radiological releases and reduces the possibility of overfilling by minimizing the accumulation of feedwater. These actions also enable the operator to establish a pressure differential between the ruptured and intact steam generators as a necessary step toward terminating primary-to-secondary flow. It was assumed that AFW flow to the ruptured steam generator would be isolated when a specific level in the steam generator was reached. At MPS3, operators are trained to isolate AFW to the ruptured SG at the level specified in the plant EOPs. This level is 8 percent NRS. The overfill analysis modeled a conservatively high AFW isolation level of 30 percent NRS. Since the addition of cold AFW water will reduce the SG releases from the affected SG, minimizing the AFW water addition is conservative. Thus, the dose input analysis modeled the conservatively low AFW isolation level of 8 percent NRS. It was assumed that the MSIV on the ruptured SG steamline would be closed at 25 minutes past break initiation.

Cooling down the RCS by dumping steam from the intact steam generators.

> The RCS is cooled down as rapidly as possible to a temperature less than the saturation temperature corresponding to the ruptured steam generator's pressure. The cooldown is performed using the available intact steam generators' MSPRBVs since neither the steam dump valves nor the condenser were available following the assumed loss-of-offsite power. The cooldown continues until RCS subcooling at the ruptured steam generator pressure is 20°F, plus an allowance of 32°F for instrument uncertainty.

Depressurizing the RCS after cooldown to minimize break flow and restore pressurizer level.

> Depressurizing the RCS is required to ensure an adequate RCS inventory and reliable pressurizer level indication prior to stopping injection. Since offsite power was assumed to be lost at the time of reactor trip, the reactor coolant pumps were not running, and thus normal

pressurizer spray was not available. It was assumed that the operator depressurized the RCS using a PORV. The operator continues to depressurize until any of the following is satisfied:

- RCS pressure is less than the ruptured steam generator pressure and pressurizer level is greater than 16 percent, or
- Pressurizer level is greater than 73 percent, or
- RCS subcooling is less than the 32°F allowance for subcooling instrument uncertainty.

Terminating safety injection to prevent re-pressurization of the RCS and terminate primary to secondary flow.

Safety injection is terminated when all of the following are satisfied:

- The RCS pressure is 50 psia above the ruptured SG pressure (indicating that the RCS pressure is stable or increasing).
- The RCS subcooling is greater than the 32°F allowance for subcooling instrument.
- Secondary heat sink is available.
- The pressurizer level is greater than the 16 percent allowance for level uncertainty.

Following termination of tube rupture flow, the operator is required to perform additional actions to bring the plant to MODE 5 (cold-shutdown) conditions. These operator actions are defined in the WOG E-3 Guidelines. Only two of the actions were explicitly considered in the analysis.

1. The operator is required to cool the RCS to the RHRS in-service temperature by feeding and steaming the available intact steam generators. The SGTR long-term mass-release analysis assumed the operator performs this action by dumping steam to the atmosphere via the MSPRBVs. Although other preferable cooldown methods (such as steam dump to the condenser to minimize activity releases) are identified in the WOG Guidelines, steam dump to the atmosphere was necessary because offsite power was assumed to be lost at the time of reactor trip, causing the condenser to be unavailable.

2. Cooldown and depressurization of the ruptured steam generator is performed after the RCS is cooled to the RHRS in-service temperature. With a loss-of-offsite power, the operator releases steam from the ruptured steam generator to the atmosphere. (This method is conservative for radiological calculations since it maximizes the activity released from the plant.) The operator maintains equal pressure between the RCS and ruptured steam generator secondary side using the PORV as needed until the RHRS is brought online.

Explicit operator action times were not defined since cooldown can proceed more gradually after tube rupture flow is terminated. For the case of the single failure of the MSPRV, it was conservatively assumed that RHR cut-in conditions are reached at 11 hours. This maximizes the steam releases during the 2-11 hour period. For other scenarios, the average mass release over the 2-11 hour period is used to conservatively bound the mass releases for RHR entry up to 24 hours.

Input Parameters and Initial Conditions

Parameters and initial conditions common to the margin-to-overfill and mass-release analyses were:

The plant was at 102 percent rated thermal power, operating at the high (589.5°F), or low (571.5°F, including 10°F coastdown) end of the T_{avg} window, depending on the case analyzed. Intermediate T_{avg}s were not explicitly analyzed. The low end of the T_{avg} range results in the highest break flow and the lowest steam releases to the atmosphere, which is conservative for margin to overfill. The highest T_{avg} results in the highest steam releases to the atmosphere, which is conservative for the mass-release analysis. An intermediate T_{avg} would not result in higher break flow and would not yield more conservative steam releases. Sensitivity analyses were performed to determine the limiting T_{avg} for the margin to overfill and mass-release analyses.

The highest worth rod cluster control assembly was stuck in its fully withdrawn position at reactor trip.

Reactor trip occurred when the overtemperature T setpoint was reached. No reactor trip delay was assumed since it maximized the secondary side inventory in the ruptured steam generator and steam releases from all steam generators. It was also assumed that loss-of-offsite power occurred at the time of reactor trip.

The turbine automatically tripped following a reactor trip. Zero delay was assumed since it minimized the steam flow to the turbine, and maximized the secondary side water inventory in the ruptured steam generator and steam releases from all steam generators.

The condenser was unavailable for steam dump following reactor trip due to the assumed loss-of-offsite power. All subsequent automatic steam relief was through the MSPRVs, and MSSVs, if needed.

A low MSPRV setpoint of 1140 psia was used since control at lower steam generator pressures caused a greater primary-to-secondary side pressure differential and tube rupture flow.

Maximum Safeguards safety injection flow was injected into all four reactor coolant loops. This assumption conservatively increased the break flow through the ruptured steam generator.

Auxiliary feedwater from all three pumps was automatically started following reactor trip and loss-of-offsite power. The flow was equally split between the steam generators, which were at nearly equal pressures until isolation.

Operation of charging and letdown systems and pressurizer heaters were not modeled. Operating these systems delays the reactor trip, which reduces the severity of the analyzed transient.

Conservatively high decay heat rates were used. The increased heat input resulted in greater tube rupture flow after reactor trip due to the longer time needed for removing heat and depressurizing the RCS.

For the margin-to-overfill cases:

The initial water mass in all steam generators corresponded to 90 percent of the nominal full power mass. A lower initial mass in the ruptured steam generator was determined to be conservative for reducing the margin to overfill.

A turbine runback was not assumed since it delays reactor trip. An earlier reactor trip results in greater steam releases to the atmosphere from the steam generators.

The maximum auxiliary feedwater flow was modeled since it was determined to provide the lowest margin to overfill.

For the mass-release analyses:

The steam generator water mass corresponded to 110 percent of nominal full power mass plus a penalty for turbine runback. A higher initial mass in the ruptured steam generator was determined to increase the post-trip flashed break flow and total integrated break flows, which are the primary contributors to the offsite doses.

The turbine runback on overtemperature ΔT at 10 percent per minute prior to reactor trip was simulated but not credited for delaying reactor trip. Turbine runback increased the secondary water mass with reduced load, because the feedwater controller attempted to maintain steam generator level as power decreased before the trip. The ruptured steam generator's fluid mass was artificially increased to simulate a turbine runback to 77 percent power prior to trip. The mass modeled in the analysis corresponded to the initial maximum level at full power, plus the differential mass between 100 percent and 77 percent power.

The maximum auxiliary feedwater flow was modeled since it was determined to provide the most conservative mass-release data.

Acceptance Criteria

No acceptance criteria are used for the margin-to-overfill and mass-release analyses. Both analyses are performed using conservative assumptions to demonstrate the ability of the operator to limit the system transient and establish parameters for providing a bounding radiological consequence assessment.

In order to demonstrate that water release from the ruptured steam generator did not have to be considered in the radiological consequences assessment, the margin-to-overfill analysis was performed to demonstrate that the secondary side of the ruptured steam generator did not completely fill with water. The available secondary side volume of a single MPS3 steam generator is 5850 ft^3. Margin to overfill was demonstrated, provided the transient calculated steam generator secondary side water volume was less than 5850 ft^3.

The radiological consequences analysis acceptance criteria for the SGTR are discussed in Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms.

2.8.5.6.2.2.3 Description of Analyses and Evaluations

The margin-to-overfill analyses were performed using the methodology in WCAP-10698 (Reference 1) with plant-specific parameters. The ruptured steam generator's secondary side water volume was calculated as a function of time to demonstrate that overfill did not occur. The analysis was performed from the start of the rupture until break flow was terminated at equalization of primary-and-secondary pressures. The implementation of the methodology includes the explicit modeling of operator actions in the WOG E-3 Guidelines required for mitigation of the SGTR accident. Operator training SGTR scenarios are used to confirm the applicability of assumptions for operator actions.

The mass-release analyses were performed using the methodology in WCAP-10698 and its supplement (References 1 and 2). The plant response, the integrated primary to secondary break flow, the feedwater flows to all steam generators, and the steam releases to the condenser (pre-trip) and to the atmosphere (post-trip) up to the time the tube rupture flow was terminated were all calculated using LOFTTR2 results. When calculating the amount of break flow that flashed to steam, 100 percent of the break flow was assumed to come from the hot leg side of the break.

The steam release and feedwater flow from the time of tube rupture flow termination to 2 hours, and from 2 to 11 hours, were determined from mass-and-energy balances using the RCS and steam generator conditions. Following termination of the tube rupture flow, the intact steam generators' MSPRBVs were assumed to cool down the plant at less than the maximum allowable rate of 80°F/hour to an RHRS in-service temperature of 350°F.

The ruptured steam generator was assumed to be depressurized to the RHRS in-service pressure of 390 psia. The amount of steam released was determined from mass-and-energy balances; no changes in thermodynamic conditions were assumed from termination of the tube rupture flow until depressurization was started since the ruptured steam generator was isolated.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal Application for the impact on the SGTR analysis. As stated in Section 2.8.5.6.2.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.6.2.2.4 Results

Only the results for the limiting margin-to-overfill and mass-release cases are presented.

SGTR Margin-to-Overfill Transient Analysis

Results are presented for the worst-case margin-to-overfill analysis. The minimum margin-to-overfill occurred with a steam generator tube plugging level of 10 percent, with the reactor initially operating with T_{avg} at 571.5°F, maximum FW temperature, low initial secondary water mass, and maximum AFW flow. The sequence of events is summarized in Table 2.8.5.6.2-2 and Figures 2.8.5.6.2-1 to 2.8.5.6.2-6 show primary and secondary side responses until the SGTR flow was terminated.

Once the break was initiated, the reactor coolant flow to the secondary side through the ruptured tube immediately caused the pressurizer level and pressure to decrease, as shown in Figures 2.8.5.6.2-1 and 2.8.5.6.2-2. The continued decrease in pressurizer pressure caused the overtemperature ΔT setpoint to be reached in 135 seconds, followed by immediate reactor and turbine trips. The reactor coolant pumps tripped due to the assumed loss-of-offsite power at the time of reactor trip. Immediately following reactor trip, the temperature differential across the hot and cold legs decreased as core power decayed.

With the steam dump valves closed after trip (due to the loss-of-condenser vacuum resulting from the assumed loss-of-offsite power at the time of reactor trip), the secondary side pressures in all steam generators increased rapidly to the MSPRV setpoint as shown in Figure 2.8.5.6.2-3. The pressurizer level and pressure continued to drop, and safety injection was actuated via the low-pressurizer pressure setpoint at 145 seconds.

It is assumed that the ruptured steam generator is by throttling auxiliary feedwater flow when the level in the steam generator reached 30 percent NRS and isolating steam flow 25 minutes after break initiation (see Table 2.8.5.6.2-2). After auxiliary feedwater isolation, the increase in fluid mass in the ruptured steam generator (shown in Figure 2.8.5.6.2-4) was due to the ruptured tube flow.

There is an 8-minute delay time before initiating the cooldown (see Table 2.8.5.6.2-1). Two of the intact steam generators' MSPRBVs were assumed to fail at the start of cooldown. At 1980 seconds, the RCS cooldown was initiated using the MSPRBV on the single available intact SG. The subsequent reduction in the available intact steam generator's pressure is shown in Figure 2.8.5.6.2-3. The pressurizer pressure also decreased during this cooldown, as shown in Figure 2.8.5.6.2-2. The cooldown was continued until RCS subcooling at the ruptured steam generator pressure was 20°F, plus an allowance of 32°F for instrument uncertainty. The RCS cooldown using the MSPRBV of the intact SG is completed after the RCS cooldown target temperature is reached, at 2850 seconds.

It is assumed that depressurization of the RCS using the pressurizer PORV is initiated after a 3-minute delay from the end of the cooldown (see Table 2.8.5.6.2-1). Depressurization was terminated at 3124 seconds when the RCS pressure was reduced below the ruptured steam generator's pressure and the pressurizer's level was greater than 16 percent. The depressurization reduced pressurizer pressure and the break flow and increased safety injection flow to refill the pressurizer, as shown in Figures 2.8.5.6.2-1, 2.8.5.6.2-2 and 2.8.5.6.2-5.

A 6-minute delay was imposed prior to termination of safety injection flow (see Table 2.8.5.6.2-1). This was well after the safety injection termination criteria were satisfied. Safety injection termination is assumed at 3484 seconds and the RCS pressure began to decrease, as shown in Figure 2.8.5.6.2-2. The primary-to-secondary flow continued until the RCS and ruptured steam generator pressures equalized at approximately 5082 seconds.

The primary-to-secondary break flow rate and water volume in the ruptured steam generator are shown in Figure 2.8.5.6.2-5 and 2.8.5.6.2-5, respectively. Figure 2.8.5.6.2-6 shows 698 ft^3 margin-to-overfill relative to the steam generator's available secondary volume of 5850 ft^3. Therefore, it was concluded that overfill of the ruptured steam generator would not occur for a design basis SGTR for MPS3.

The net effect of the SPU and associated changes in initial conditions and operator action timing assumptions are an increase in the margin-to-overfill relative to the MPS3 analysis of record.

SGTR Mass-Release Transient Analysis

The maximum mass release occurred with a steam generator tube plugging level of 0 percent, with the reactor initially operating with T_{avg} at 571.5°F, minimum FW temperature, high initial secondary mass, and maximum AFW flow. The sequence of events is summarized in Table 2.8.5.6.2-3, and the primary and secondary side responses are shown in Figures 2.8.5.6.2-7 to 2.8.5.6.2-18. Total mass releases for use in the dose analyses are summarized in Table 2.8.5.6.2-4.

The mass-release transient modeled a high initial secondary inventory and maximum auxiliary feedwater flow. The ruptured steam generator level reached the AFW isolation level of 8 percent at 178 seconds. Isolating the ruptured steam generator's steamline was delayed until 1500 seconds, consistent with Table 2.8.5.6.2-1. At 1502 seconds, the ruptured steam generator's MSPRV was assumed to fail open. The failure of the MSPRV caused the steam generator to rapidly depressurize, and the primary-to-secondary flow through the ruptured tube to increase (see Figures 2.8.5.6.2-9 and 2.8.5.6.2-12). The ruptured steam generator's depressurization caused the RCS pressure and temperature to decrease rapidly (see Figures 2.8.5.6.2-8, 2.8.5.6.2-9, and 2.8.5.6.2-10). It is assumed that the stuck open MSPRV is identified and the isolation for the failed valve is closed after 20 minutes. The depressurization of the ruptured steam generator stopped at 2702 seconds, and its pressure began to increase, as shown in Figure 2.8.5.6.2-9.

There is an 8-minute delay time imposed prior to initiating cooldown after the failed-open MSPRVs block valve was closed (see Table 2.8.5.6.2-1). The cooldown was performed using all three intact steam generators' MSPRBVs to dump steam to the atmosphere, and continued until the RCS subcooling at the ruptured steam generator pressure was 20°F, plus an allowance of 32°F for instrument uncertainty. The cooldown was completed at 3690 seconds. Because of the lower pressure in the ruptured steam generator when the cooldown was initiated, the RCS had to be cooled to a lower temperature to satisfy the cooldown criterion. The net effect was that the cooldown period was longer, relative to the overfill case. The reductions in the intact steam generators' pressure and the RCS temperature during the cooldown period are shown in Figures 2.8.5.6.2-8, 2.8.5.6.2-9, and 2.8.5.6.2-10, respectively. The intact steam generators' MSPRBVs were later reopened to maintain RCS temperature and subcooling margin.

After a 3-minute delay (see Table 2.8.5.6.2-1), it is assumed that the pressurizer PORV is used to depressurize the RCS. Depressurization was terminated at 3952 seconds, when the RCS pressure was less than the ruptured steam generator pressure and the pressurizer level was greater than 16 percent. During depressurization, safety injection flow refilled the pressurizer while break flow was reduced, as shown in Figures 2.8.5.6.2-7 and 2.8.5.6.2-12, respectively.

At this point, a 6-minute delay (see Table 2.8.5.6.2-1) was assumed before terminating safety injection at 4312 seconds. The RCS pressure then began to decrease, as shown in Figure 2.8.5.6.2-8. Figures 2.8.5.6.2-12 shows that the primary-to-secondary flow continued until the RCS and ruptured steam generator pressures equalized at approximately 6412 seconds.

Figures 2.8.5.6.2-16 and 2.8.5.6.2-17 show the steam release to the atmosphere from the ruptured and intact SGs, respectively, until break flow termination. Figure 2.8.5.6.2-13 shows the primary-to-secondary pressure differential which is used, together with the ruptured loop hot leg temperature in Figure 2.8.5.6.2-10 and the break flow rate in Figure 2.8.5.6.2-12 to calculate the flashed break flow. Figure 2.8.5.6.2-18 shows the integrated flashed break flow.

The ruptured SG water volume is shown in Figure 2.8.5.6.2-15. For this case the water volume in the ruptured SG is significantly less than the available secondary volume of 5850 ft^3 when break flow is terminated. The mass of water in the ruptured SG is also shown as a function of time in Figure 2.8.5.6.2-15.

Following termination of the tube rupture flow, the RCS was cooled down using the intact steam generators. The steam releases are presented in Table 2.8.5.6.2-4. Since the condenser was in service until reactor trip, any radioactivity released to the atmosphere before reactor trip was through the condenser air ejector. After reactor trip, the releases were assumed to be via the MSPRVs. For the RCS cooldown and continued cooling, the releases are through the MSPRBVs. Table 2.8.5.6.2-4 indicates that approximately 198,330 lbm of steam was released to the atmosphere from the ruptured steam generator within the first 2 hours (i.e., the ruptured steam generator was isolated within this interval). After 2 hours, 40,920 lbm of steam was released to the atmosphere from the ruptured steam generator, when it was depressurized after the RCS was cooled to the RHRS in-service temperature. A total of 229,790 lbm of reactor coolant flowed through the tube rupture before break flow was terminated. The intact steam generators' release rate to the atmosphere is 186,487 lbm/hr from 2 hours until RHR.

The analysis performed to calculate the mass transfer data for input to the radiological consequences analysis has been completed and data tabulated for the limiting case. The results of the analysis were used as input to the radiological consequences analysis presented in Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms.

2.8.5.6.2.3 Conclusion

DNC has reviewed the analysis of the SGTR accident and concludes that the analysis has adequately accounted for the operation of the plant at the proposed power level and was performed using acceptable analytical methods and approved computer codes. DNC further concludes that the assumptions used in this analysis are conservative and that the event does not result in an overfill of the faulted (ruptured) SG. Mass-release data are provided for a bounding radiological consequence assessment. Therefore, DNC finds the proposed SPU acceptable with respect to the SGTR event.

2.8.5.6.2.4 References

1. WCAP-10698-P-A (Proprietary), *SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill*, Lewis, Huang, Behnke, Fittante, Gelman, August 1987. (Currently incorporated within the FSAR.)

2. WCAP-10698-P-A (Proprietary) Supplement 1, *Evaluation of Offsite Radiation Doses for a Steam Generator Tube Rupture Accident*, Lewis, Huang, Rubin, March 1986. (Currently incorporated within the FSAR.)

Table 2.8.5.6.2-1
Operator Action Times For Design Basis SGTR Analysis

Action	Time
Isolate AFW flow to the ruptured SG	Calculated time to reach 30% narrow range level in the ruptured steam generator for overfill analysis Calculated time to reach 8% narrow range level in the ruptured steam generator for mass-release analysis (input to doses)
Isolate ruptured steam generator MSIV	25 minutes from the time of break initiation
Operator action time to isolate failed-opened MSPRV (in mass-release analysis)	20 minutes
Operator action time to initiate cooldown	8 minutes from complete isolation of ruptured steam generator
Cooldown	LOFTTR2 Calculated time for RCS cooldown
Operator action time to initiate depressurization	3 minutes from end of cooldown
Depressurization	LOFTTR2 Calculated time for RCS depressurization
Operator action time to initiate safety injection termination	Maximum of 6 minutes from end of depressurization or time to satisfy safety injection termination criteria
Pressure equalization	LOFTTR2 calculated time for equalization of RCS and ruptured steam generator pressures

Table 2.8.5.6.2-2
Sequence of Events for Limiting Margin-to-overfill Analysis

Event	Time (seconds)
SGTR	0
Reactor trip	135
SI actuated	145
AFW Flow Initiated	165
Ruptured SG AFW Flow Isolated	794
Ruptured SG steamline isolated	1500
RCS cooldown initiated	1980
RCS cooldown terminated	2850
RCS depressurization initiated	3030
RCS depressurization terminated	3124
Safety injection terminated	3484
Break flow terminated	5082

Table 2.8.5.6.2-3
Sequence of Events for Input to Radiological Consequences Analysis

Event	Time (seconds)
SGTR	0
Reactor trip	135
SI actuated	143
Ruptured SG AFW Isolation Level Reached	178
Ruptured SG steamline isolated	1500
Ruptured SG MSPRV fails open	1502
Ruptured SG MSPRV block valve closed	2702
RCS cooldown initiated	3182
Break flow stops flashing	3381
RCS cooldown terminated	3690
RCS depressurization initiated	3872
RCS depressurization terminated	3952
Safety injection terminated	4312
Break flow terminated	6412

Table 2.8.5.6.2-4
Mass Releases Total Mass Flow (Pounds)

	Time Period			
	Start of Event to Time of Reactor Trip	**Time of Reactor Trip to Time at Which Break Flow is Terminated**	**Time at Which Break Flow is Terminated to 2 Hours**	**2 Hours to 11 Hours**
Ruptured SG				
To Condenser (lbm)	159,610	0	0	0
To Atmosphere (lbm)	0	198,330	0	40,920
Feedwater Flow (lbm)	152,680	11,770	0	0
Intact SGs (total for 3)				
To Condenser (lbm)	475,090	0	0	0
To Atmosphere (lbm)	0	344,190	47,960	1,678,380
Feedwater Flow (lbm)	475,090	470,690	35,420	1,833,040
Total Break Flow (lbm)	7,040	222,750	0	0
Flashed Break Flow (lbm)	1,138.6	14,506.9	0	0

Figure 2.8.5.6.2-1 SGTR (Overfill), Pressurizer Level vs. Time

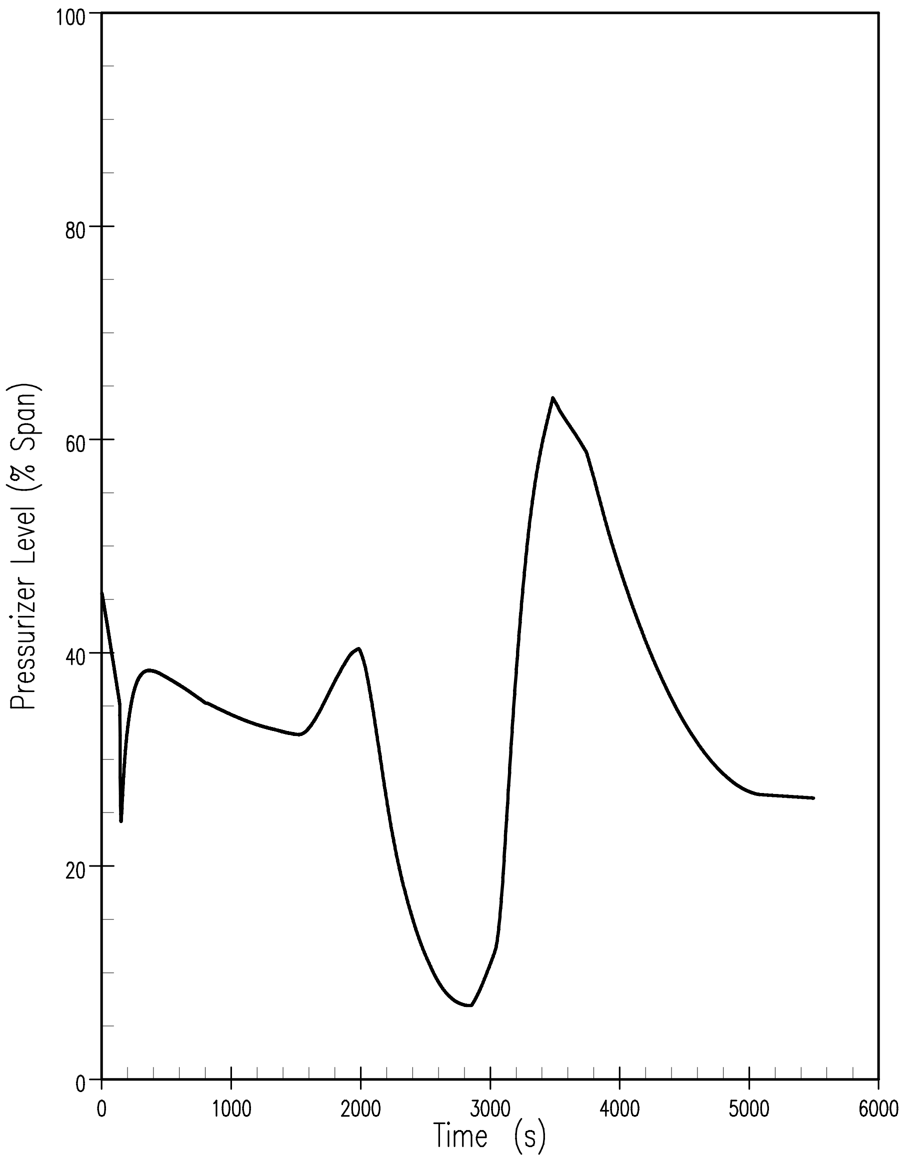


Figure 2.8.5.6.2-2 SGTR (Overfill), RCS Pressure vs. Time

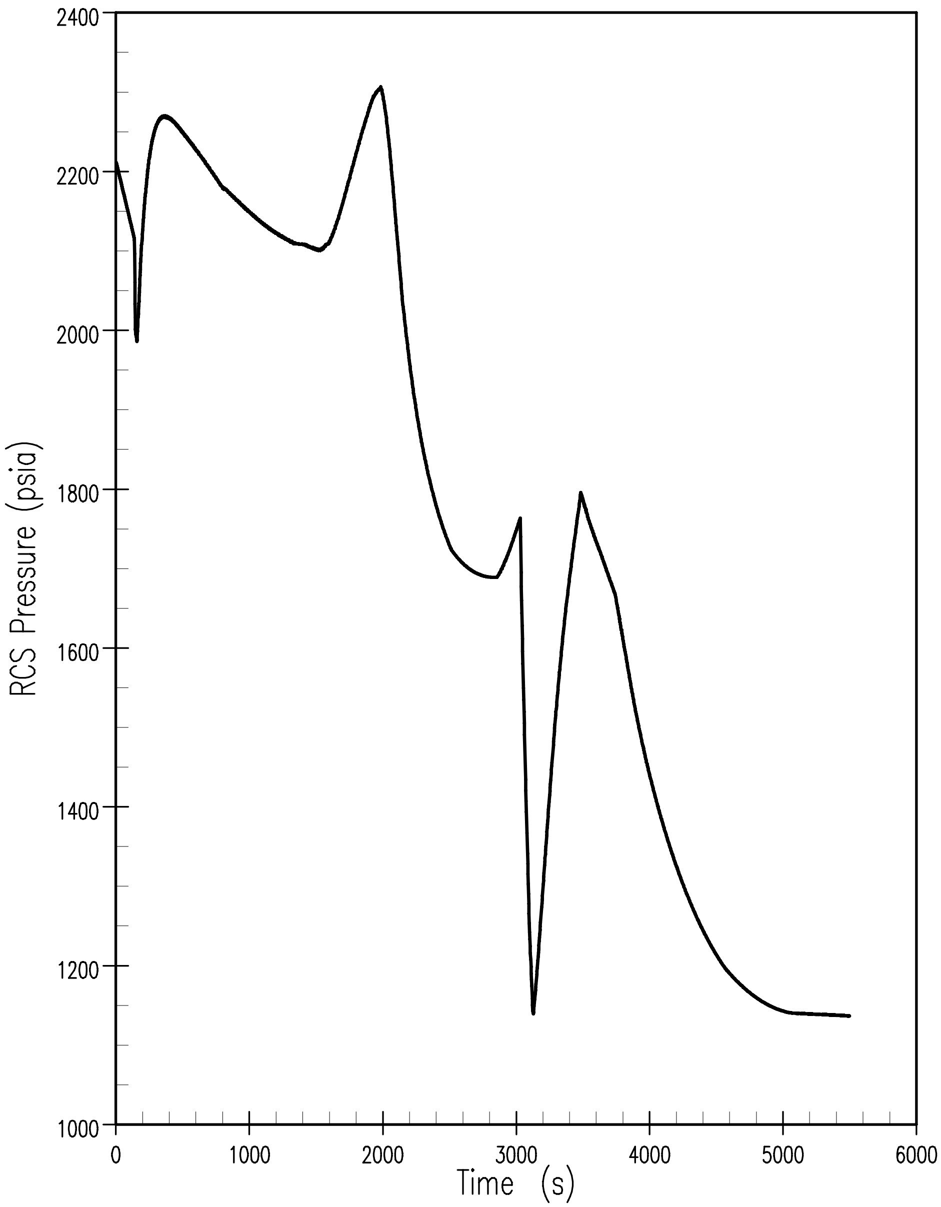


Figure 2.8.5.6.2-3 SGTR (Overfill), Secondary Pressure vs. Time

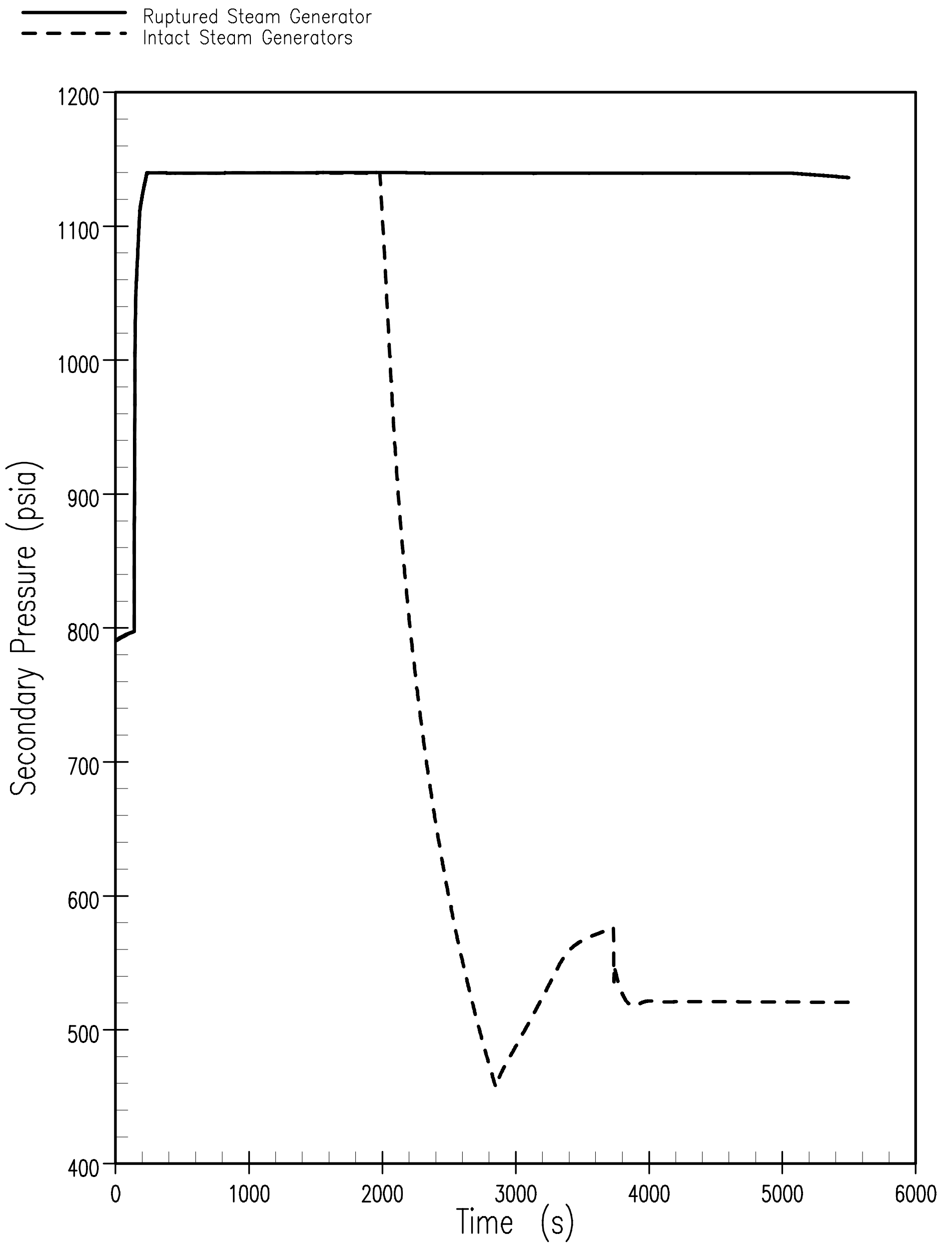


Figure 2.8.5.6.2-4 SGTR (Overfill), Ruptured SG Water Mass vs. Time

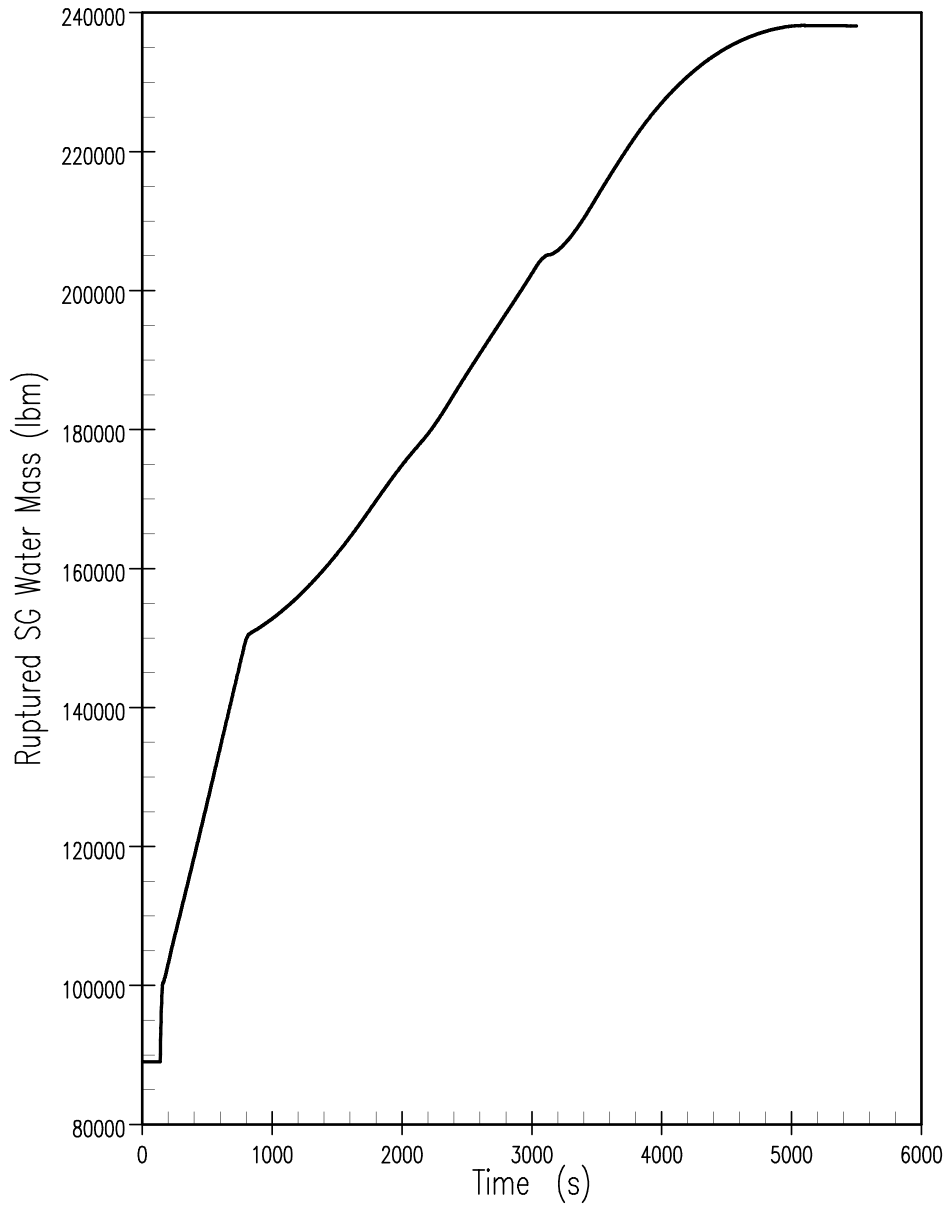


Figure 2.8.5.6.2-5 SGTR (Overfill), Primary to Secondary Break Flow Rate vs. Time

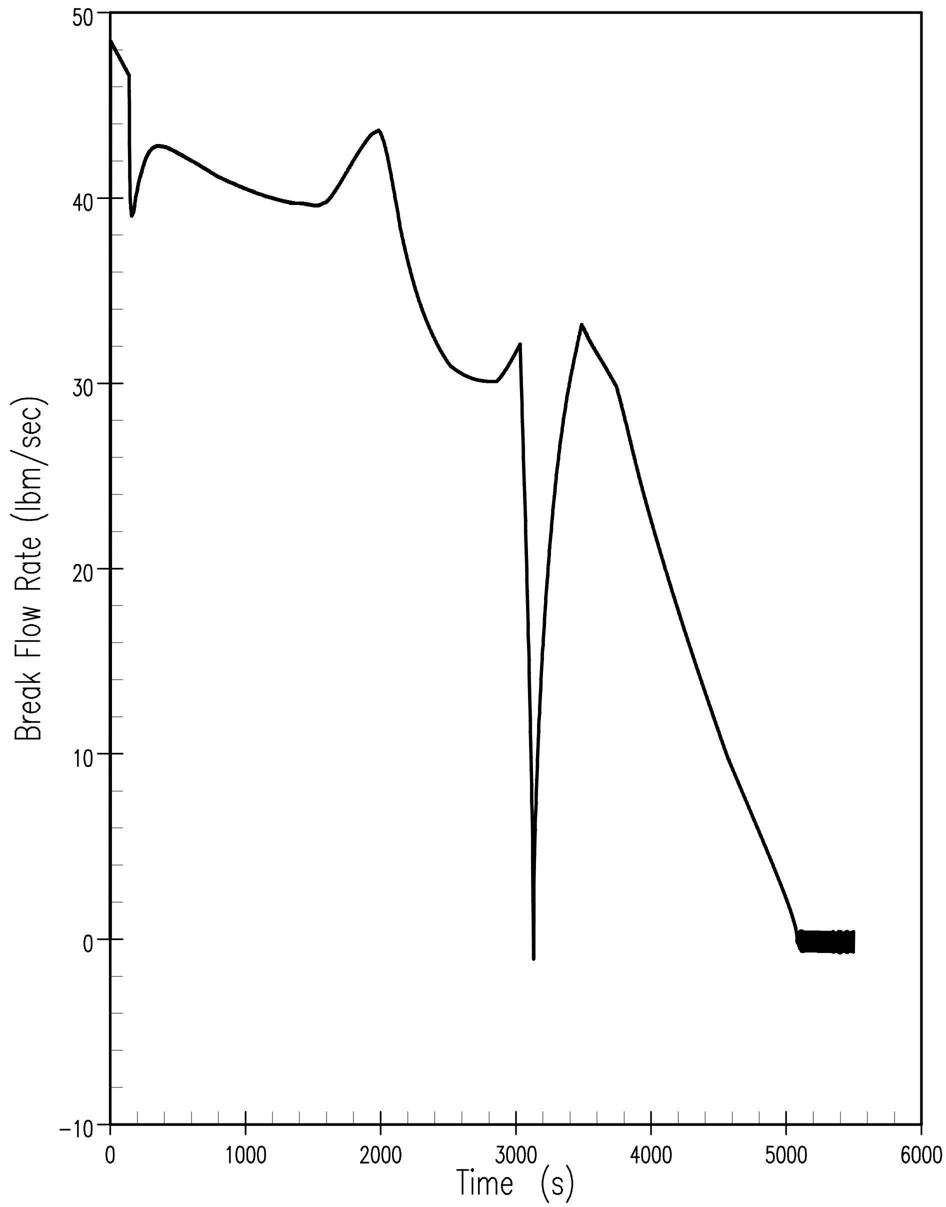


Figure 2.8.5.6.2-6 SGTR (Overfill), Ruptured SG Water Volume vs. Time

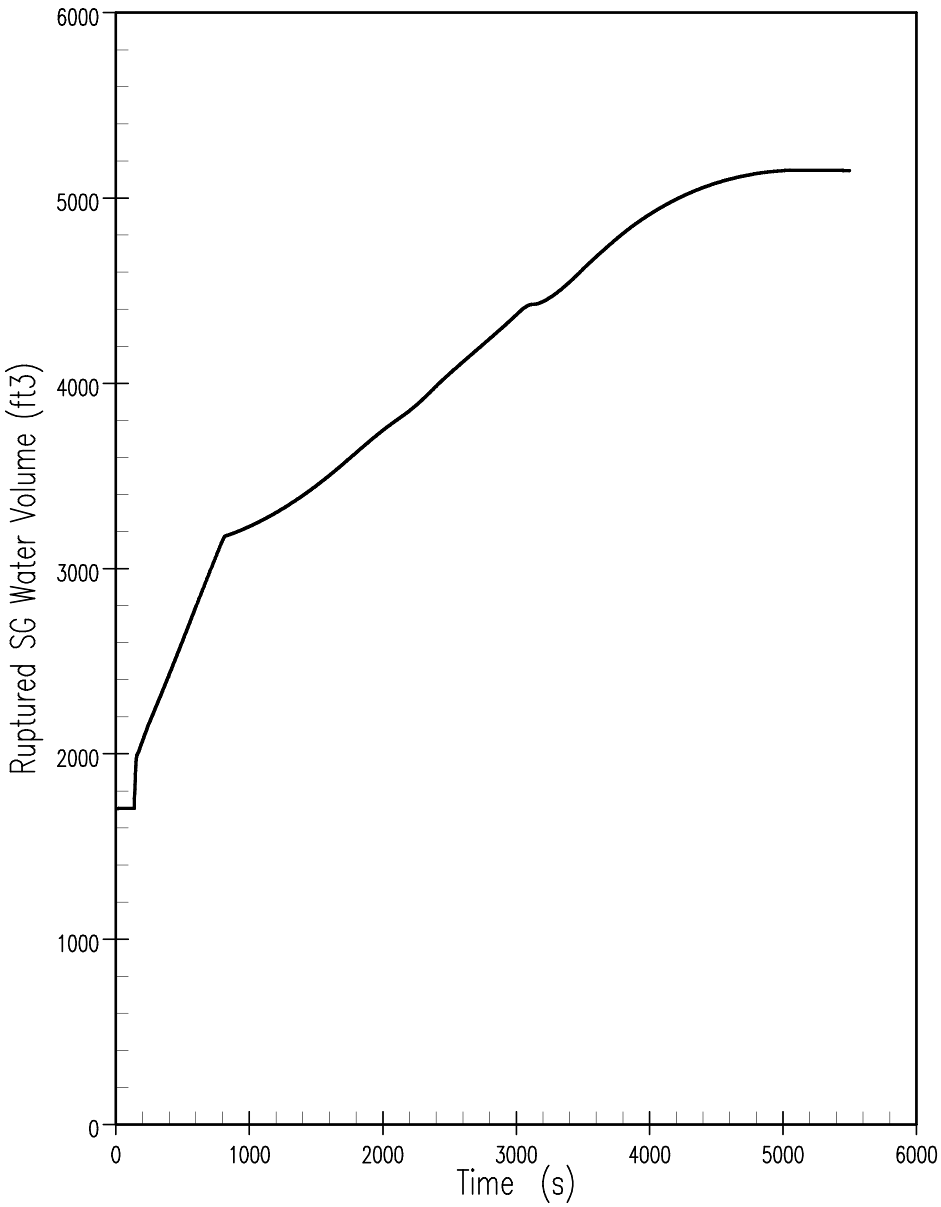


Figure 2.8.5.6.2-7 SGTR (Dose), Pressurizer Level vs. Time

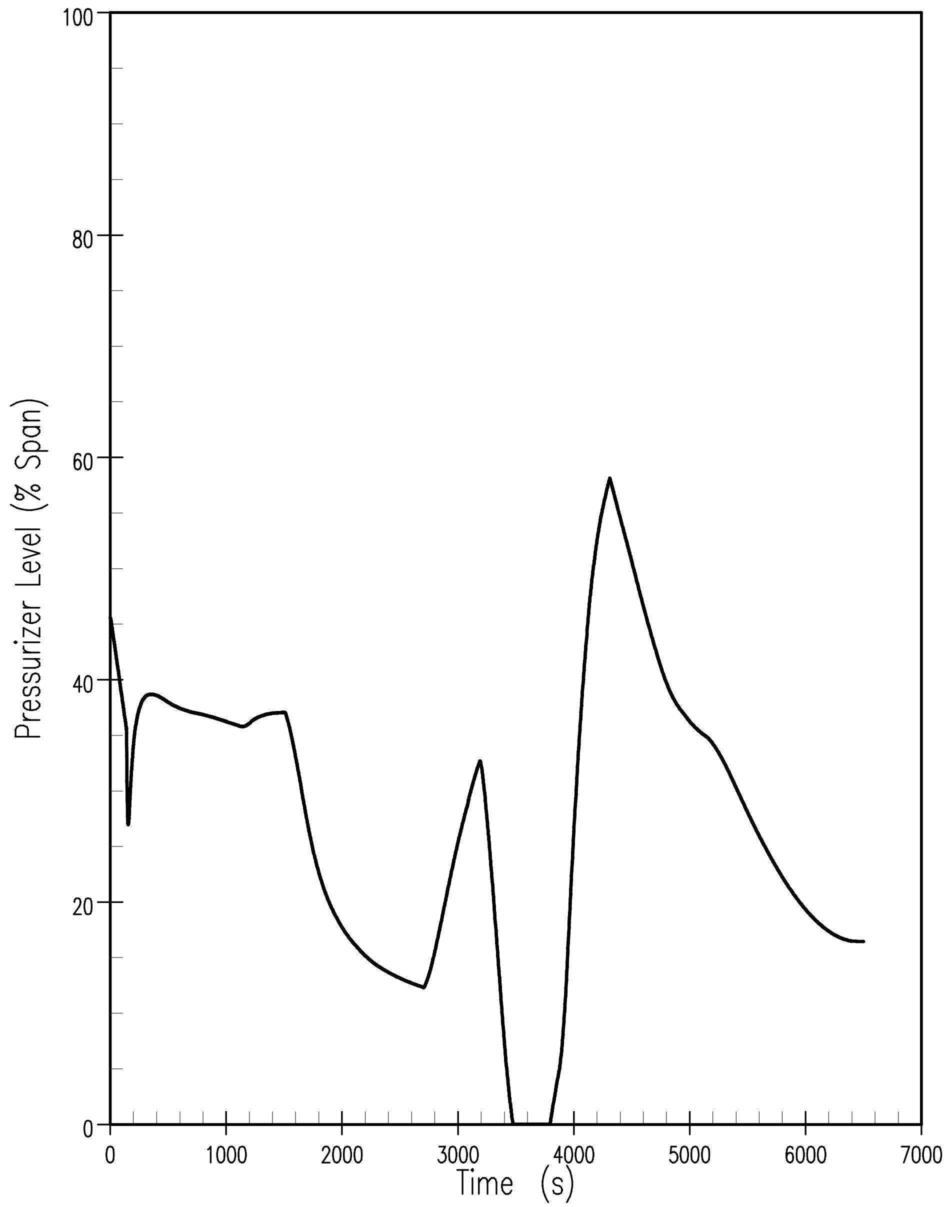


Figure 2.8.5.6.2-8 SGTR (Dose), RCS Pressure vs. Time

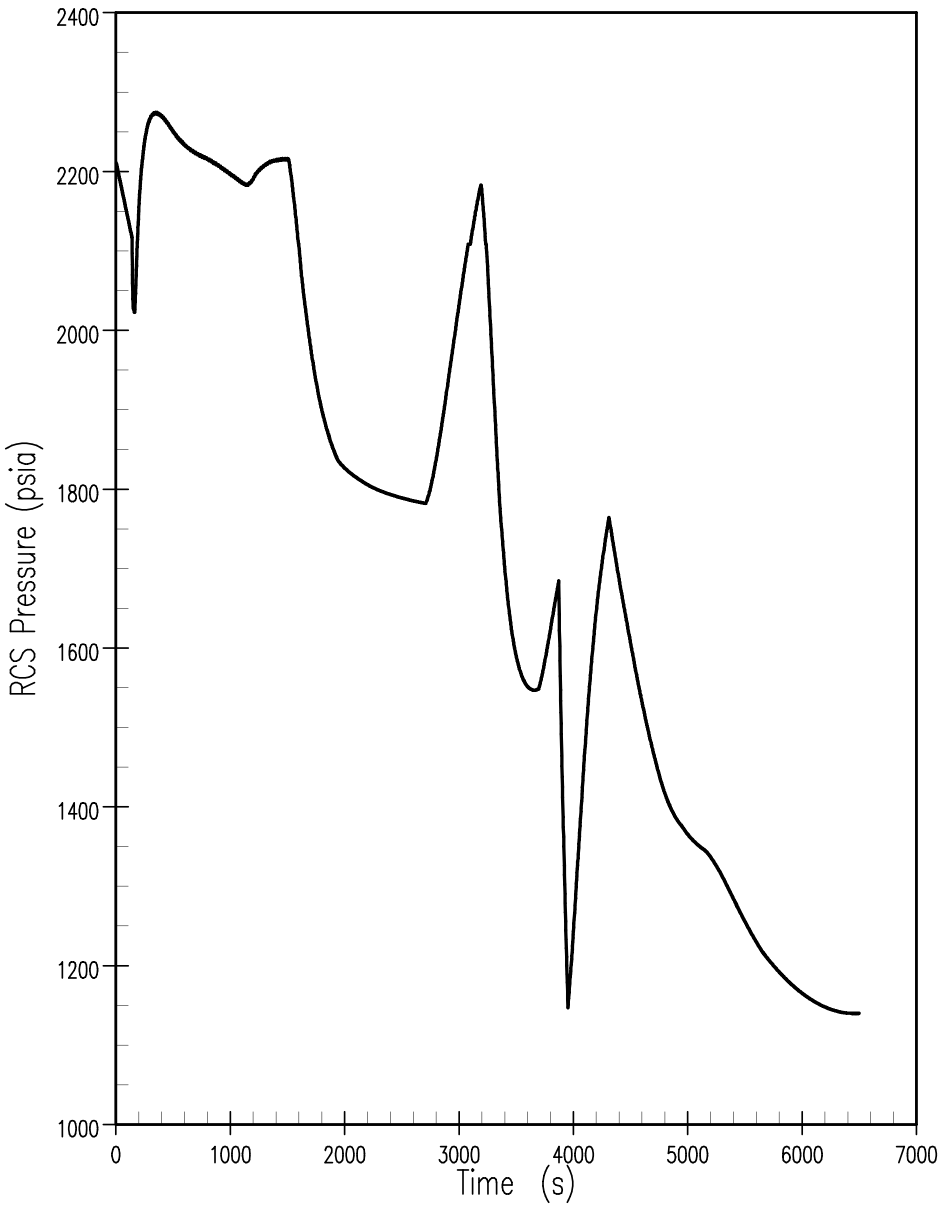


Figure 2.8.5.6.2-9 SGTR (Dose), Secondary Pressure vs. Time

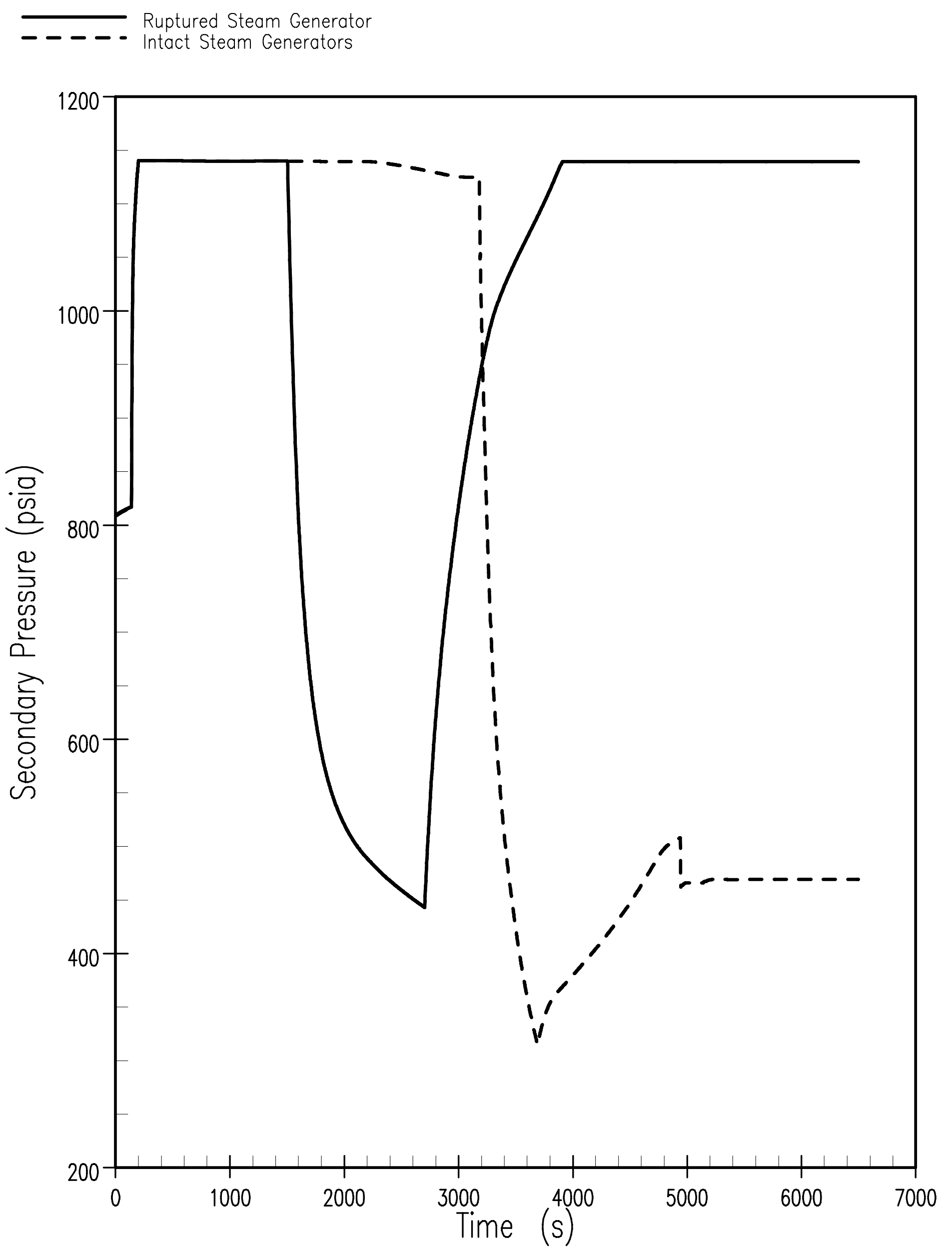


Figure 2.8.5.6.2-10 SGTR (Dose), Ruptured Loop Hot and Cold Leg RCS Temperatures vs. Time

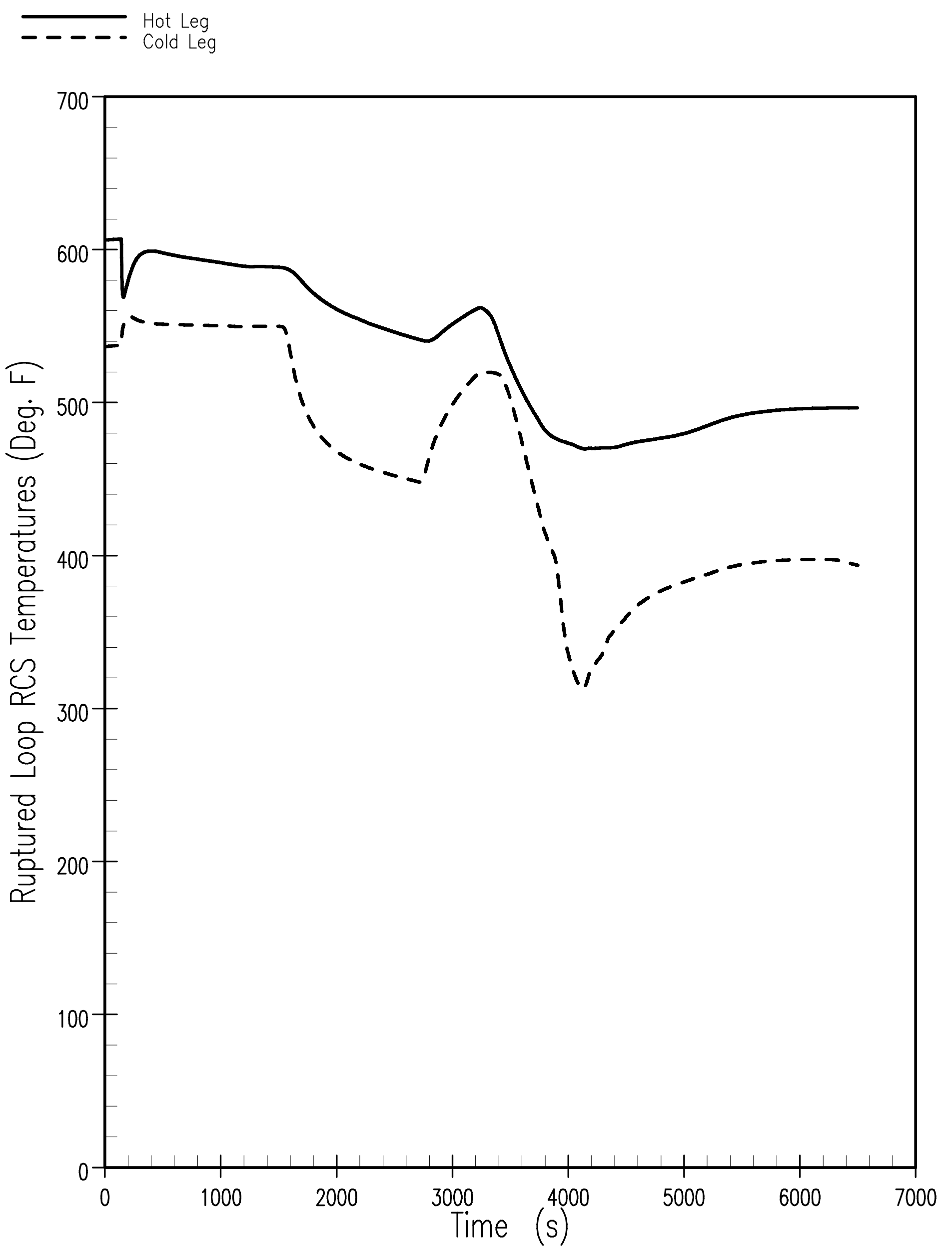


Figure 2.8.5.6.2-11 SGTR (Dose), Intact Loop Hot and Cold Leg RCS Temperatures vs. Time

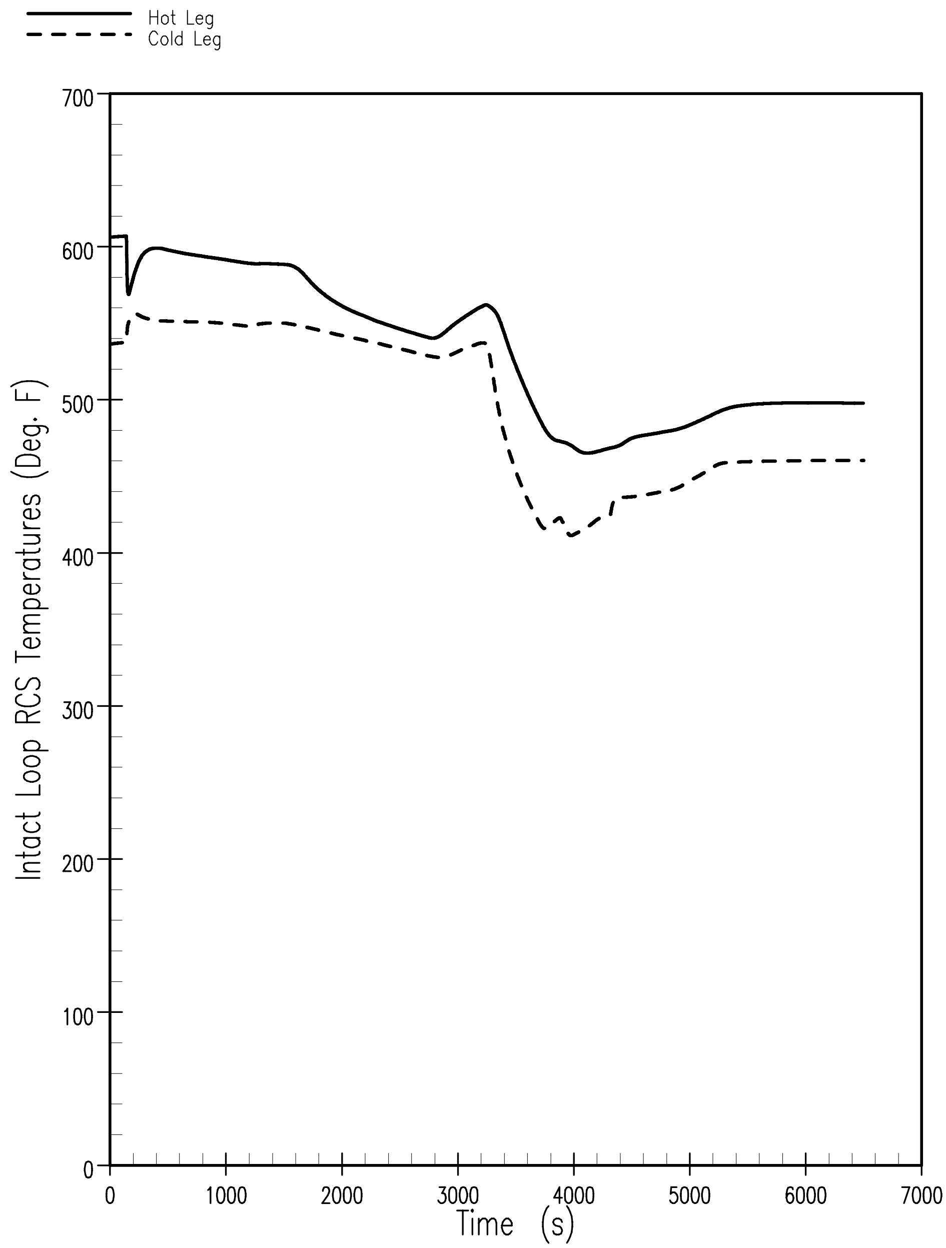


Figure 2.8.5.6.2-12 SGTR (Dose), Primary to Secondary Break Flow Rate vs. Time

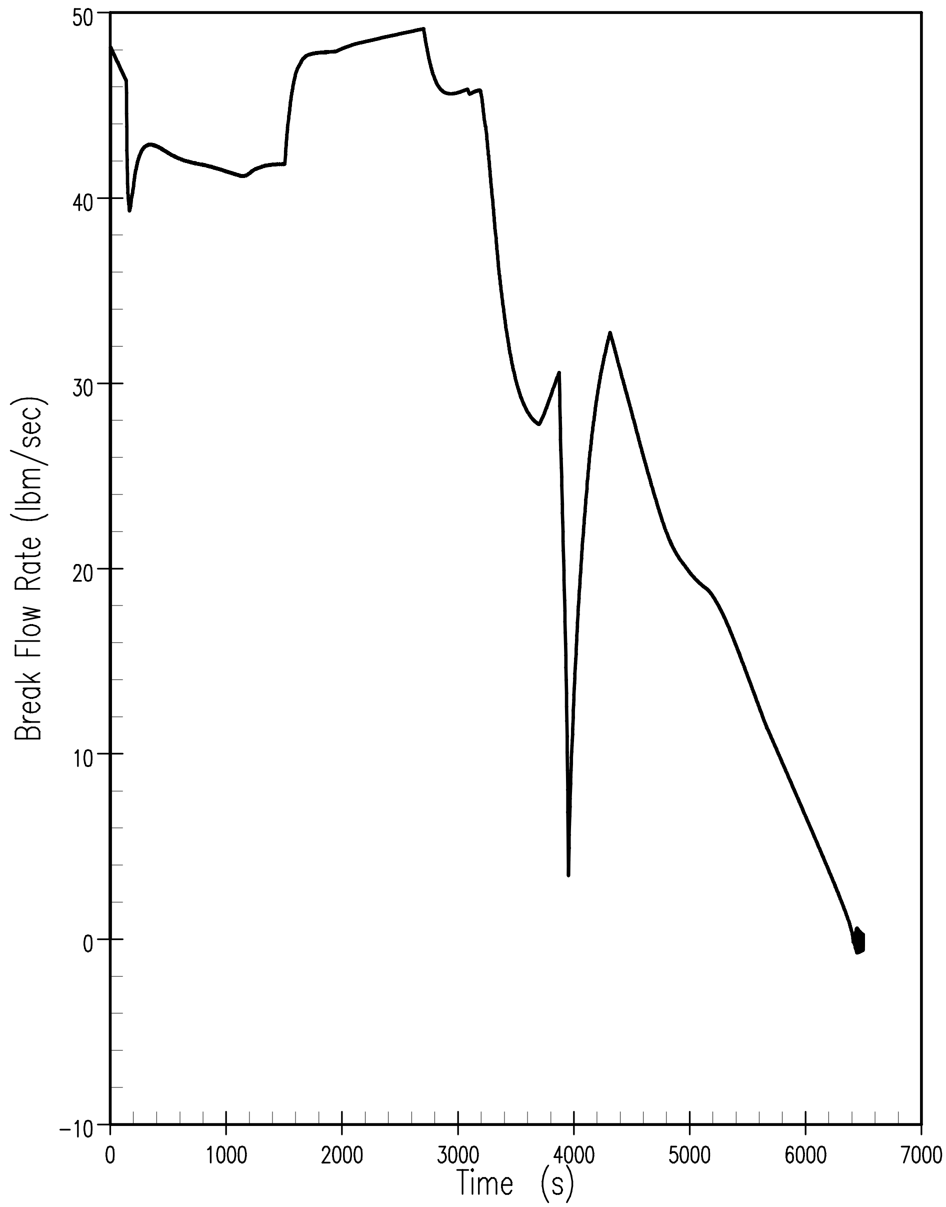


Figure 2.8.5.6.2-13 SGTR (Dose), Differential Pressure Between RCS and Ruptured SG vs. Time

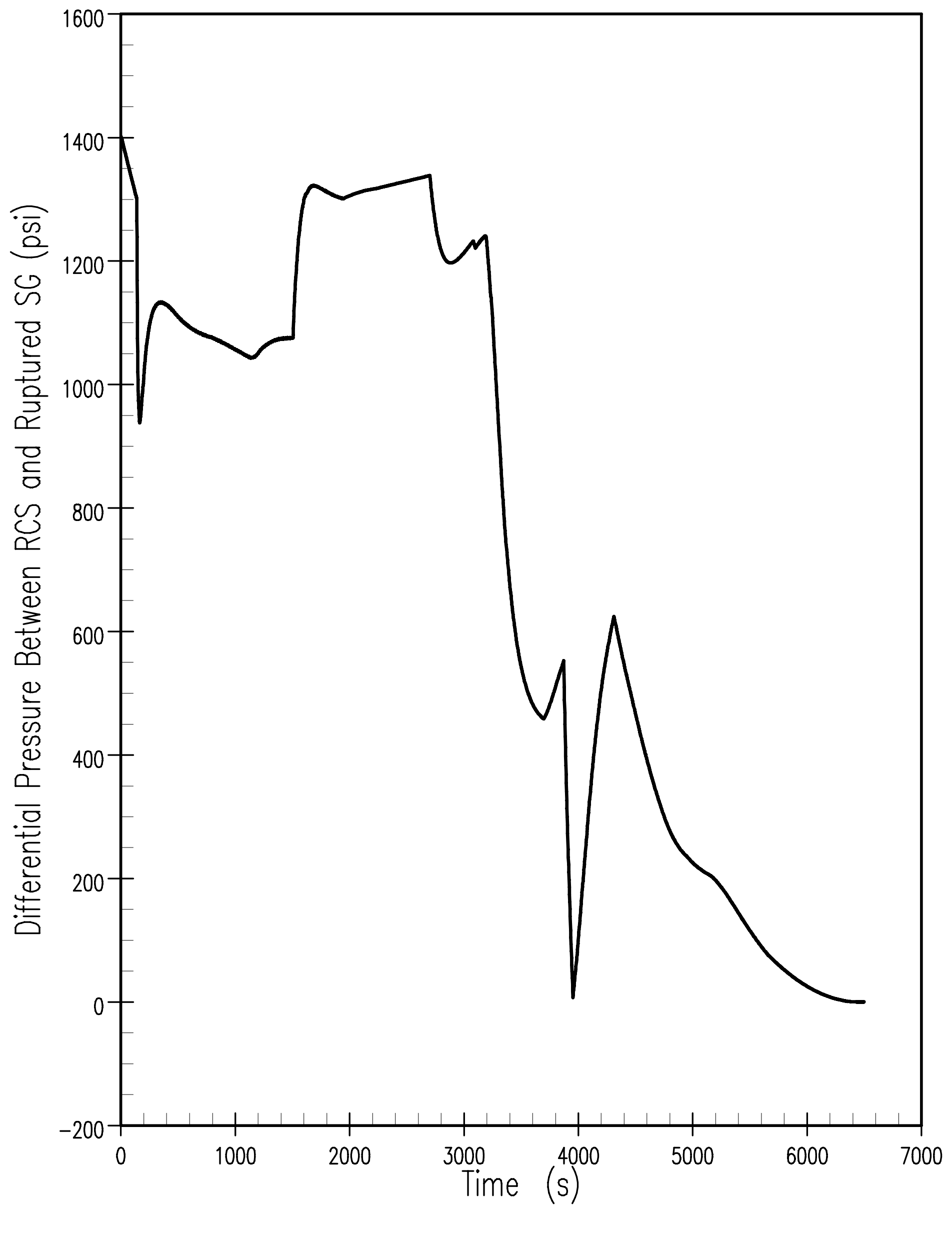


Figure 2.8.5.6.2-14 SGTR (Dose), Ruptured SG Water Volume vs. Time

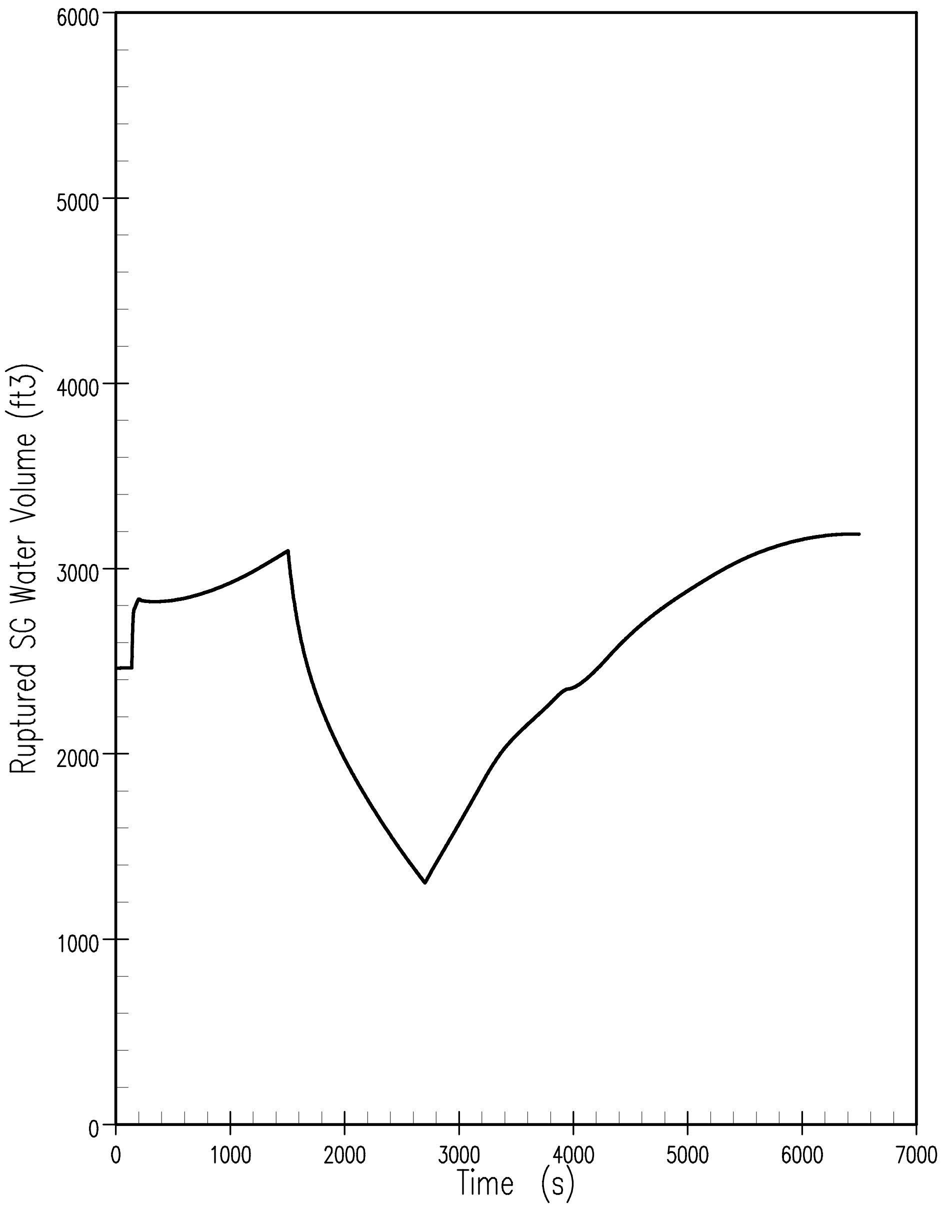


Figure 2.8.5.6.2-15 SGTR (Dose), Ruptured SG Water Mass vs. Time

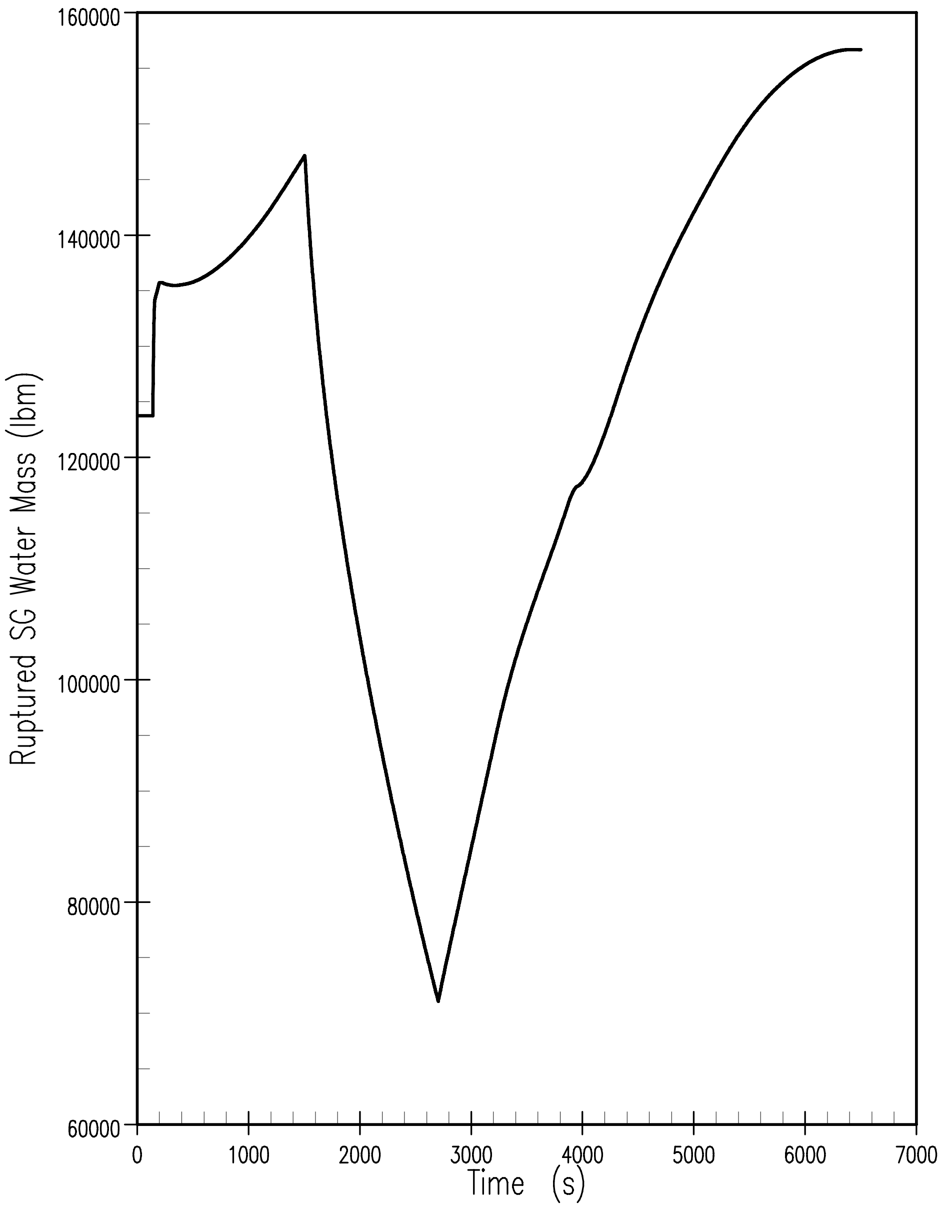


Figure 2.8.5.6.2-16
SGTR (Dose), Ruptured SG Mass Release Rate to the Atmosphere vs. Time

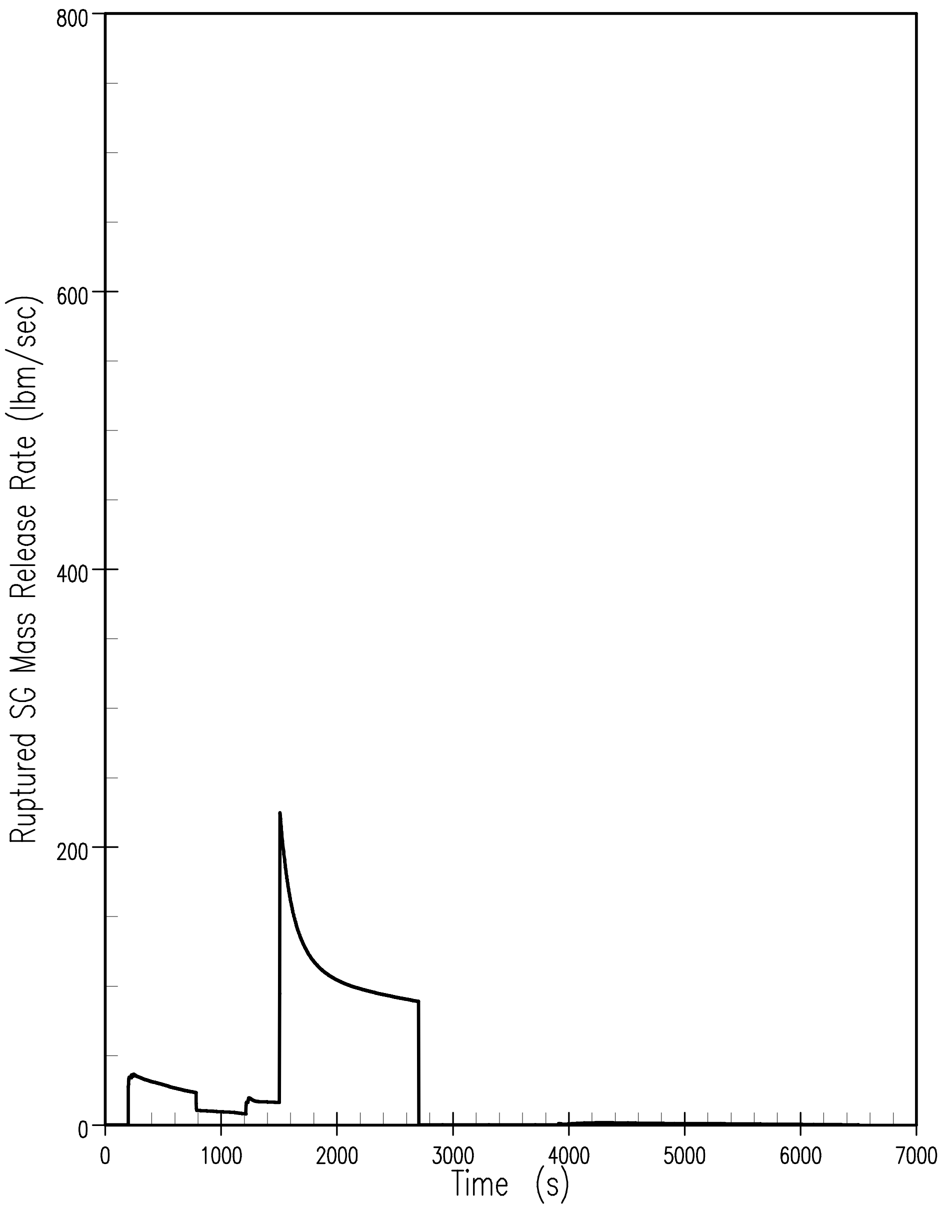


Figure 2.8.5.6.2-17
SGTR (Dose), Intact SGs Mass Release Rate to the Atmosphere vs. Time

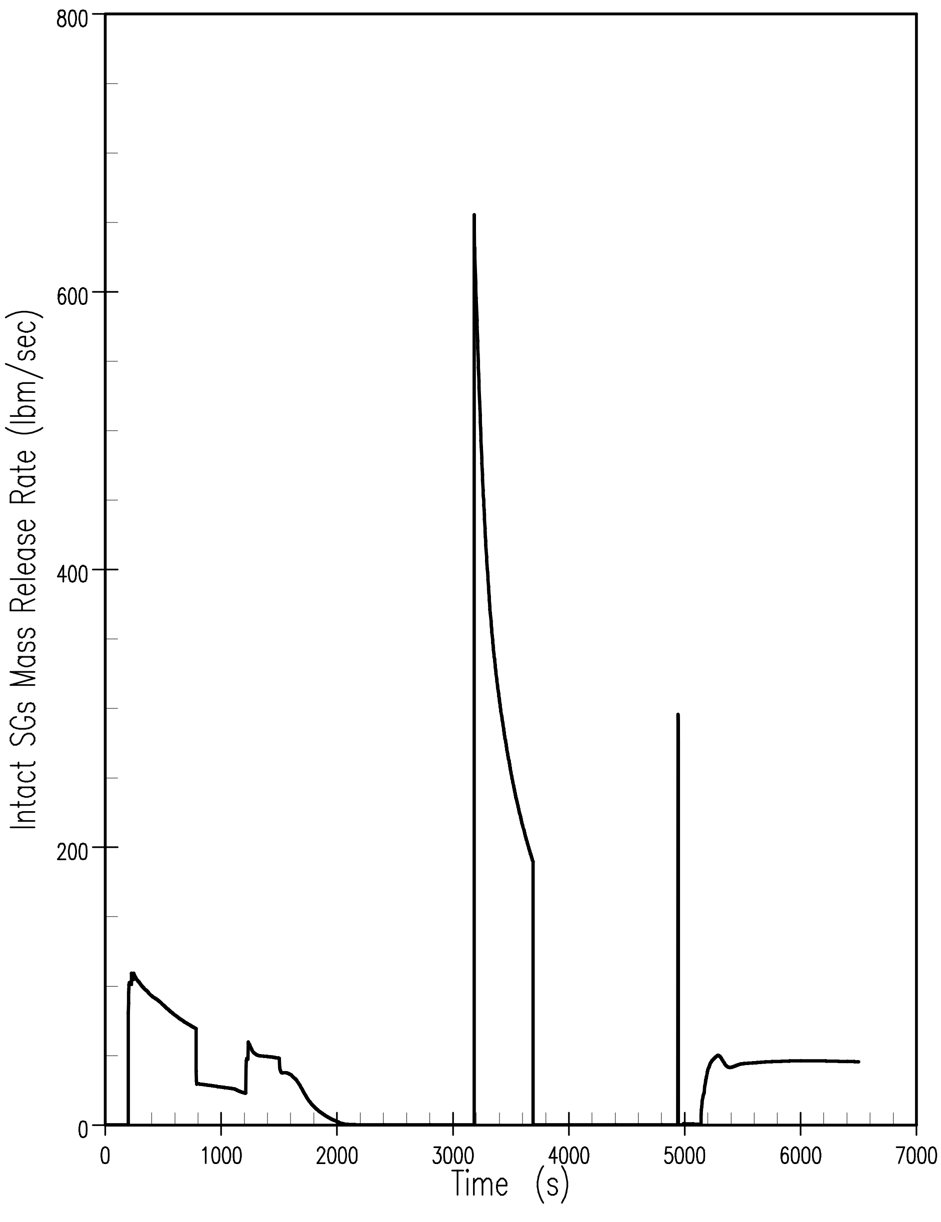
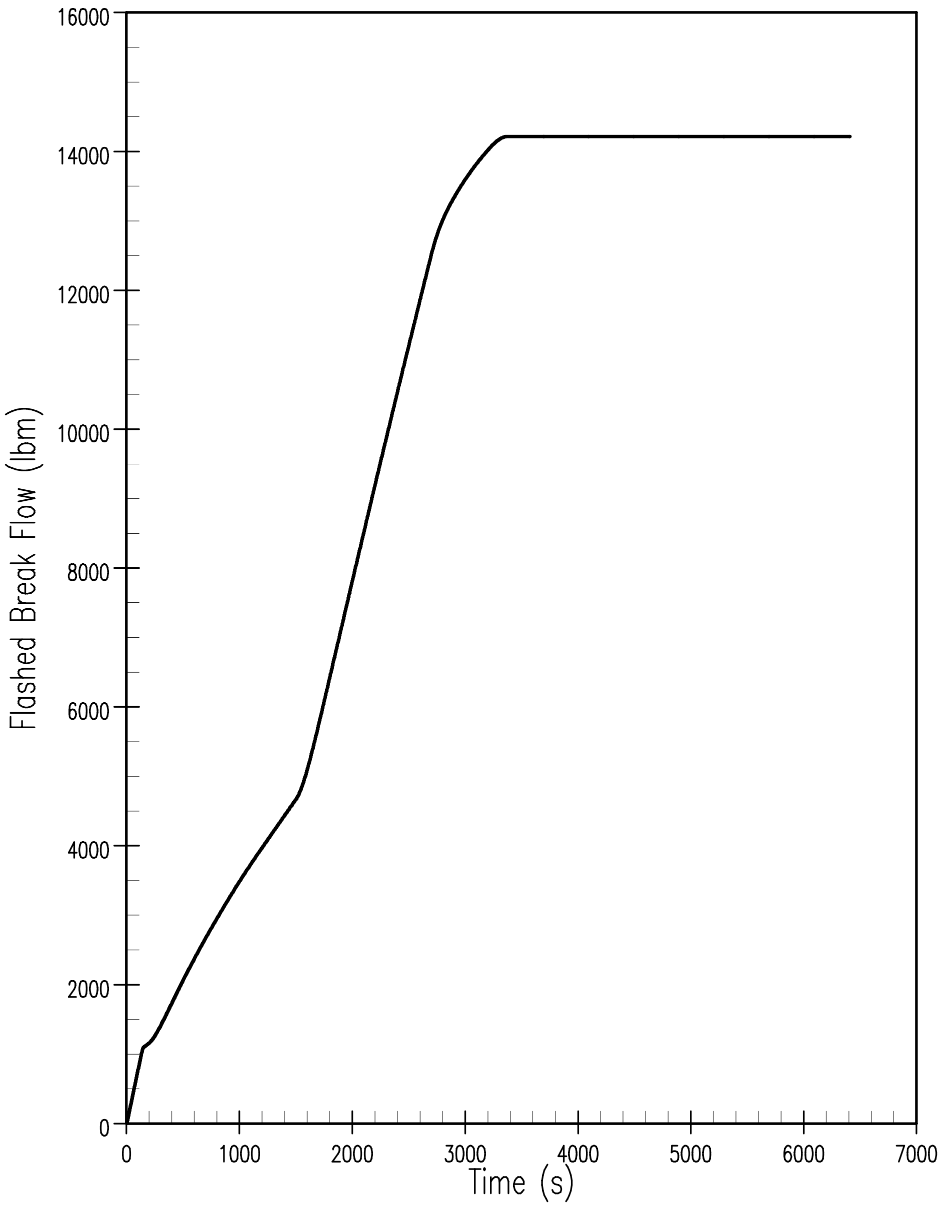


Figure 2.8.5.6.2-18 SGTR (Dose), Flashed Break Flow vs. Time



2.8.5.6.3 Emergency Core Cooling System and Loss-of-Coolant Accidents

2.8.5.6.3.1 Regulatory Evaluation

LOCAs are postulated accidents that would result in the loss of reactor coolant from piping breaks in the reactor coolant pressure boundary at a rate in excess of the capability of the normal reactor coolant makeup system to replenish it. Loss of significant quantities of reactor coolant would prevent heat removal from the reactor core, unless the water is replenished. The RPS and ECCS are provided to mitigate these accidents.

The DNC review covered:

- The determination of break locations and break sizes
- The postulated initial conditions
- The sequence of events
- The analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients
- The calculations of peak cladding temperature, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling
- The functional and operational characteristics of the RPS and ECCS
- Operator actions

The acceptance criteria are based on:

- 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance
- 10 CFR 50, Appendix K, insofar as it establishes required and acceptable features of evaluation models by the ECCS after the blowdown phase of a LOCA
- GDC-4, insofar as it requires that structures, systems, and components important-to-safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer
- GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained
- GDC-35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel and clad damage that could interfere with continued effective core cooling will be prevented.

Specific review criteria are contained in SRP Sections 6.3 and 15.6.5, and guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP Sections 15.6.5, Rev. 2 and 6.3, Rev. 1.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the general design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to:

- GDC-4, Environmental and Missile Design Bases, is described in the FSAR Section 3.1.2.4.

  Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety related systems to ensure that each such system performs its intended safety function.

  In a letter from B. J. Youngblood (NRC) to J. F. Opeka (NNEC) dated June 5, 1985, MPS3 was granted an exemption for a period of two cycles of operation from those portions of GDC-4 which require protection of structures, systems, and components from the dynamic effects associated with postulated breaks in the reactor coolant system primary loop piping.

  In the Federal Register, Volume 51, No. 70, dated April 11, 1986, the NRC published a final rule modifying GDC-4 to allow use of leak-before-break technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in pressurized water reactors. This rule obviates the need for the above exemption.

  Structures, systems, and components important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in FSAR Section 3.2.5.

- GDC-27, Combined Reactivity Control Systems Capability, is described in FSAR Section 3.1.2.27.

  MPS3 is provided with a means of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. FSAR Chapters 4 and 9 (CVCS) discuss these means in detail. Combined use of the rod cluster control system and the chemical shim control system permit the necessary shutdown margin to be maintained during long-term xenon decay and plant cooldown. The single highest worth control cluster is assumed to be stuck full-out upon trip for this determination. FSAR Chapter 15 describes accident assumptions in detail.

- GDC-35, Emergency Core Cooling, is addressed in FSAR Section 3.1.2.35.

  An ECCS is provided to cope with any LOCA in the plant design basis. Abundant cooling water is available in an emergency to transfer heat from the core at a rate such that the core is maintained in a coolable geometry and that the clad metal - water reaction is limited to less than one percent. Adequate design provisions are made to assure performance of the required safety functions even with a single failure. The ECCS is further described in FSAR Section 6.3. FSAR Chapter 15 includes an evaluation of the adequacy of the safety functions. Performance evaluations are conducted in accordance with 10 CFR 50.46 and 10 CFR 50, Appendix K.

A LOCA is the result of a pipe rupture of the reactor coolant pressure boundary. FSAR Section 15.6.5.1 provides the following definitions:

- A major pipe break (large break) is defined as a rupture with a total cross-sectional area equal to or greater than 1.0 ft^2. This event is considered an ANS Condition IV event.
- A minor pipe break (small break) is defined as a rupture of the reactor coolant pressure boundary with a total cross-sectional area less than 1.0 ft^2 in which the normally operating charging system flow is not sufficient to sustain pressurizer level and pressure. This is considered a Condition III event.

FSAR Table 15.6-8 lists important input parameters and initial conditions used in the analyses of the large and small break LOCAs, and FSAR Table 15.6-1 provides the postulated sequence of events for both large and small break LOCAs.

Large Break LOCA

For the large break LOCA, FSAR Section 15.6.5.3 states that the following codes were utilized to assess the core heat transfer geometry and to determine if the core remains amenable to cooling throughout and subsequent to the blowdown, refill, and reflood phases of the LOCA:

- SATAN VI (WCAP-8302 and WCAP-8306),
- WREFLOOD (WCAP-8170 and WCAP-8171),
- COCO (WCAP-8237 and WCAP-8326),
- BART (WCAP-9561-P-A, Rev. 1 with Addendum 1-3, and WCAP-9695-A),
- BASH (WCAP-10266-P-A, Rev. 2 with Addenda and WCAP-10337-A), and
- LOCBART (WCAP-8301, WCAP-8305, WCAP-10266-P-A, Rev. 2, with Addenda, and WCAP-10337-A) codes are used

FSAR Section 15.6.5.3 states that a break in the RCS cold-leg piping results in the highest calculated PCT for double-ended guillotine breaks. Therefore, a spectrum covering a range of discharge coefficients for DECLG were analyzed.

The large break LOCA analysis resulted in a Peak Clad Temperature of 1974°F for the limiting DECLG break at a total peaking factor of 2.60. The maximum local metal-water reaction was 4.55 percent, and the total core-wide metal-water reaction was less than 1.0 percent for all cases analyzed. Further, the clad temperature transients turned around at a time when the core geometry was still amenable to cooling.

FSAR Section 15.6.5.5 concludes that the analysis demonstrated that the acceptance criteria described in 10 CFR 50.46 and 10 CFR 50, Appendix K, are met.

Small Break LOCA

FSAR Section 15.6.5.3 states that the small break analysis was performed with the Westinghouse ECCS Evaluation Model using NOTRUMP (WCAP 10079-P-A and WCAP 10054-P-A), including changes to the model and methodology as described in WCAP 10054-P-A, Addendum 2, Revision 1 and WCAP 15085. The NOTRUMP Evaluation Model includes the following computer codes:

- NOTRUMP: Calculates the thermal-hydraulic response of RCS during transient
- SBLOCTA: Calculates the fuel rod/cladding heat-up during transient

FSAR Section 15.6.5.3 states that the limiting small break LOCA was found to be less than a 10-inch-diameter rupture of the RCS cold leg. Therefore, a range of small break cases is analyzed to establish the limiting small break. The peak cladding temperature calculated for the limiting small break LOCA is 1009°F. The maximum local metal-water reaction is below the acceptance criteria limit of 17 percent. The total core metal-water reaction is less than 1 percent acceptance criteria.

FSAR Section 15.6.5.5 concludes that the analysis demonstrated that the acceptance criteria described in 10 CFR 50.46 and 10 CFR 50, Appendix K, are met.

LOCA Hydraulic Forces

FSAR Section 3.9B.1.4.2 describes the modeling and analytical methods for evaluating the structural stress analysis for the reactor coolant loop and supports for faulted loading conditions. This section identifies that the faulted loading condition of the RCS loop and supports considers loading due to: 1) Internal pressure; 2) Weight; 3) Safe shutdown earthquake; 4) Loss-of-coolant accident (pipe break); and 5) Transients. For LOCAs, mechanical loads are developed in the broken and unbroken reactor coolant loops and in the reactor vessel as a result of transient flow and pressure fluctuations following a postulated pipe break in one of the reactor coolant loops. Time history dynamic analysis is performed for a number of postulated break cases. Hydraulic models are used to generate time-dependent hydraulic forcing functions used in the analysis of the RCS for each break case. The transient applied forces are described in FSAR Section 3.6B.2. Also, FSAR Section 3.9B.1.4.3 provides additional information.

FSAR Section 3.9N5.2 identifies the loading conditions for normal, upset, emergency and faulted conditions that form the basis for the design of the reactor internals. The design bases for the mechanical design of the reactor vessel internals relevant to LOCAs are: 1) The core internals are designed to withstand mechanical loads arising from operating basis earthquake, safe shutdown earthquake and pipe ruptures and meet the requirement of Item 2; 2) The reactor shall have mechanical provisions which are sufficient to adequately support the core and internals and to assure that the core is intact with acceptable heat transfer geometry following transients arising from abnormal operating conditions; and 3) Following the design basis accident, the plant shall be capable of being shut down and cooled in an orderly fashion so that fuel cladding temperature is kept within specified limits. This implies that the deformation of certain critical reactor internals must be kept sufficiently small to allow core cooling.

The functional limitations for the core structures during the design basis accident are shown in FSAR Table 3.9N-13. Details of the dynamic analyses, input forcing functions, and response loadings are presented in FSAR Section 3.9N.2.

Post-LOCA Boron Concentration

The MPS3 current licensing basis for post-LOCA subcriticality is embodied in the cycle-specific Reload Safety Evaluations (Technical Requirements Manual, Appendix 8.1, Core Operating Limits Report).

FSAR Section 6.3.2.5 identifies that boron precipitation in the reactor vessel can be prevented by a back-flush of cooling water through the core to reduce the concentration of boric acid in the water remaining in the reactor vessel. Two flow paths are available for hot leg recirculation of sump water. Each safety injection pump can discharge to two hot legs with suction taken from the containment recirculation pump discharge. Loss of one pump or one flow path does not prevent hot leg recirculation, since two redundant flow paths are available for use. FSAR Section 6.3.2.1 identifies that approximately 9 hours after the LOCA, cold leg recirculation is terminated and hot leg recirculation is initiated.

Other Considerations

Westinghouse NSALs 02-3 Rev. 01; 02-4, Rev. 0; and 02-5 Rev 01 identified potential non-conservative errors in SG level measurement due to the pressure drop across the SG mid deck plate; potential impacts on the SG level reactor trip setpoints; and potential impacts to SG water level control system uncertainties utilized as initial condition assumptions for SG water level related safety analyses. DNC implemented modifications to the MPS3 narrow range SG level measurement instrument loops during 3R11 (April, 2007) to address changes in instrument uncertainties for level control and setpoints used for SG low-low level reactor trip.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. Specific transient analysis is not within the scope of License Renewal.

2.8.5.6.3.2 Technical Evaluation

2.8.5.6.3.2.1 Large Break Best Estimate LOCA

This section discusses the LB BELOCA analysis prepared in support of MPS3 SPU.

2.8.5.6.3.2.1.1 Introduction

The LB BELOCA analysis is described in Section 2.8.5.6.3.2.1.3 for a major rupture of the RCPB. A major rupture (large break) is defined as a breach in the RCPB with a total cross sectional area greater than 1.0 ft^2.

This section discusses the LB BELOCA analysis prepared in support of MPS3 SPU. The LB BELOCA analysis was performed consistent with the methodology developed by Westinghouse and described in WCAP-16009-P-A (Reference 2). This analysis uses the Westinghouse statistical treatment of uncertainties methodology, ASTRUM (Automated Statistical Treatment of Uncertainty Method) to develop the PCT and oxidation results at the 95th percentile.

Prior to the issuance of WCAP-16009-P-A, LB BELOCA analyses for 3 and 4 loop plants were performed consistent with the NRC approved methodology conveyed in WCAP-12945-P-A "Code Qualification Document for Best-Estimate LOCA Analysis" (Reference 1). The analysis methodology presented in WCAP-12945-P-A is patterned after the Code Scaling, Applicability, and Uncertainty (CSAU) methodology developed under the guidance of the NRC. The ASTRUM is also patterned after the CSAU methodology. However, the uncertainty analysis is replaced by a technique based on order statistics. The ASTRUM methodology replaces the response surface technique with a statistical sampling method where the uncertainty parameters are simultaneously sampled for each case. The balance of this section will refer to the previously approved methodology (that presented in WCAP-12945-P-A) associated with performing LB BELOCA analysis as the CQD methodology.

The three 10 CFR 50.46 criteria (peak clad temperature, maximum local oxidation and core-wide oxidation) are satisfied by running a sufficient number of WCOBRA/TRAC calculations. In particular, the statistical theory predicts that 124 calculations are required to simultaneously bound the 95th percentile of the three parameters with a 95-percent confidence level.

2.8.5.6.3.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Table 2.8.5.6.3.2.1-1 lists the major plant parameter assumptions used in the ASTRUM BELOCA analysis for MPS3. Because of the methodology change, where best estimate parameters are used rather than bounding values as in the current analysis, a comparison of parameters between current analysis and SPU is not relevant. The acceptance criteria and results of the analysis are discussed in Section 2.8.5.6.3.2.1.4.

2.8.5.6.3.2.1.3 Description of Analyses

The LB BELOCA analysis has been performed for MPS3 using the methodology contained in WCAP-16009-P-A (Reference 2). This analysis has been performed in accordance with the limits and usage conditions defined in Section 13-3 of WCAP-16009-P-A, as applicable to the ASTRUM methodology. Section 13-3 of WCAP-16009-P-A acceptably dispositions each of the identified conditions and limitations related to WCOBRA/TRAC and the CQD uncertainty approach per Section 4.0 of the ASTRUM Final Safety Evaluation Report appended to WCAP-16009-P-A.

The approved methodologies used for the MPS3 SPU LB BELOCA analysis apply specifically to MPS3 since:

- The MPS3 plant-specific LB BELOCA analysis is not based on the model or analysis of any other plant. The analysis is MPS3-specific.

- MPS3 and its vendor, Westinghouse Electric Company LLC, continue to have ongoing processes which assure that LOCA analysis input values conservatively bound the as-operated plant values for those parameters.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the Large Break BELOCA Analysis. As stated in Section 2.8.5.6.3.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for License Renewal and they remain valid for the SPU conditions.

2.8.5.6.3.2.1.4 Results

The LB BELOCA analysis has been performed for MPS3 using the methodology contained in WCAP-16009-P-A (Reference 2). The results of the analysis demonstrate that the LB BELOCA acceptance criteria presented in 10 CFR 50.46 is complied with. Table 2.8.5.6.3.2.1-2 summarizes the results of the ASTRUM LB BELOCA analysis. Compliance with 10 CFR 50.46 acceptance criteria is discussed in detail below. In addition various PCT plots are provided to demonstrate that PCT is not exceeded.

Break location was generically addressed during the development of the LB BELOCA methodology. Break type and size are specifically considered for the MPS3 transient simulation. The MPS3 PCT-limiting transient is a double-ended cold leg guillotine break which is used as the basis to analyze the conditions listed in Table 2.8.5.6.3.2.1-1. The uncertainties related to break type and size were included in the model uncertainties for the MPS3 LB BELOCA PCT. Also, the MPS3 LBLOCA analysis considers downcomer boiling as WCOBRA/TRAC properly models the effects of downcomer boiling in the transient calculation.

The sequence of events following a large DEGCL break LOCA is presented in Table 2.8.5.6.3.2.1-3.

The scatter plot presented in Figure 2.8.5.6.3.2.1-1 shows the impact of the effective break area on the analysis PCT. The effective break area is calculated by multiplying the discharge coefficient C_D by the sample value of the break area, normalized to the cold-leg cross sectional area. Figure 2.8.5.6.3.2.1-1 is provided because the break area is a contributor to the variation in PCT.

Figures 2.8.5.6.3.2.1-2 and 2.8.5.6.3.2.1-3 are presented to show the limiting cladding transient for each 10 CFR 50.46 criterion analyzed in the ASTRUM BELOCA analysis. Figure 2.8.5.6.3.2.1-2 shows the HOTSPOT predicted clad temperature transient at the PCT and LMO limiting elevation for the limiting PCT and LMO case. Figure 2.8.5.6.3.2.1-3 shows the WCOBRA/TRAC predicted peak cladding temperature for the CWO limiting transient.

Additional Plots for the Limiting PCT Transient

Figures 2.8.5.6.3.2.1-4 through 2.8.5.6.3.2.1-17 were generated using the limiting PCT case. The PCT-limiting case was chosen to illustrate a conservative representation of the response to a large break LOCA.

Figure 2.8.5.6.3.2.1-4 is a plot of the pressurizer pressure throughout the PCT-limiting transient. Figures 2.8.5.6.3.2.1-1 and -6 are plots of the mass flow rate through the break (Vessel and Loop side, respectively). Figure 2.8.5.6.3.2.1-7 presents the void fraction in both the intact and broken loop pumps; the dashed curve represents the broken loop pump. Figure 2.8.5.6.3.2.1-8 is a plot of the vapor flow rate at the top third of the core above the Hot Assembly.

Figure 2.8.5.6.3.2.1-9 is a plot of an intact loop accumulator injection flow. Figure 2.8.5.6.3.2.1-10 is a plot of the Safety Injection Flow into one of the intact cold legs. Figure 2.8.5.6.3.2.1-11, 2.8.5.6.3.2.1-12, and 2.8.5.6.3.2.1-13 are plots of the lower plenum, downcomer, and core average channel collapsed liquid levels, respectively. The reference point for the downcomer liquid level is the point at which the outside of the core barrel, if extended downward, intersects with the vessel wall. The reference point for the core collapsed liquid levels is the bottom of the active fuel.

The vessel fluid inventory throughout the transient is plotted in Figure 2.8.5.6.3.2.1-14. Figure 2.8.5.6.3.2.1-15 is a plot of the Peak Clad Temperature for all 5 rods modeled in WCOBRA/TRAC, and Figure 2.8.5.6.3.2.1-16 is a plot of the hot rod PCT elevation versus time. Note, the peak clad temperatures in Figure 2.8.5.6.3.2.1-15 are the WCOBRA/TRAC calculated temperatures, not the HOTSPOT calculated temperatures (Figure 2.8.5.6.3.2.1-2 is HOTSPOT calculated temperatures).

The containment backpressure and the axial power distribution utilized in the BE LBLOCA WCOBRA/TRAC analysis is shown in Figures 2.8.5.6.3.2.1-17 and 2.8.5.6.3.2.1-18, respectively.

10 CFR 50.46 Requirements

It must be demonstrated that there is a high level of probability that the limits set forth in 10 CFR 50.46 are met. These limits are complied with as demonstrated below:

(b)(1) The limiting PCT corresponds to a bounding estimate of the 95th percentile PCT at the 95-percent confidence level. Since the resulting PCT for the limiting case is 1781°F, the analysis confirms that 10 CFR 50.46 acceptance criterion (b)(1), i.e., “Peak Clad Temperature less than 2200°F,” is demonstrated. The result is shown in Table 2.8.5.6.3.2.1-2.

(b)(2) The maximum cladding oxidation corresponds to a bounding estimate of the 95th percentile LMO at the 95-percent confidence level. The limiting transient LMO for MPS3 is 3.5 percent. The transient oxidation for MPS3 decreases from the near BOL value of 3.5 percent to a negligible value at EOL. The sum of the pre-transient plus transient oxidation remains below 17 percent at all times in life for the MPS3 fuel. Therefore, the analysis confirms that 10 CFR 50.46 acceptance criterion (b)(2), i.e., “Local Maximum Oxidation of the cladding less than 17 percent”, is demonstrated. The result of the transient oxidation is shown in Table 2.8.5.6.3.2.1-2.

(b)(3) The limiting CWO corresponds to a bounding estimate of the 95th percentile CWO at the 95-percent confidence level. The limiting Hot Assembly Rod (HAR) total maximum oxidation is 0.12 percent. A detailed CWO calculation takes advantage of the core power census that includes many lower power assemblies. Because there is significant margin to the regulatory limit, the CWO value can be conservatively chosen as that calculated for the limiting HAR. A detailed CWO calculation is not needed because the outcome is always less than 0.12 percent. Therefore, the analysis confirms that 10 CFR 50.46 acceptance criterion (b)(3), i.e., “Core-Wide Oxidation less than 1 percent”, is demonstrated. The result is shown in Table 2.8.5.6.3.2.1-2.

(b)(4) 10 CFR 50.46 acceptance criterion (b)(4) requires that the calculated changes in core geometry are such that the core remains amenable to cooling. This criterion has historically been satisfied by adherence to criteria (b)(1) and (b)(2), and by assuring that fuel deformation due to combined LOCA and seismic loads is specifically addressed. It has been demonstrated that the PCT and maximum cladding oxidation limits remain in effect for Best-Estimate LOCA applications. The approved methodology (Reference 1) specifies that effects of LOCA and seismic loads on core geometry do not need to be considered unless grid crushing extends beyond the 44 assemblies in the low-power channel; this situation is not calculated to occur for MPS3. Therefore, acceptance criterion (b)(4) is satisfied.

(b)(5) 10 CFR 50.46 acceptance criterion (b)(5) requires that long-term core cooling be provided following the successful initial operation of the ECCS. Long-term cooling is dependent on the demonstration of continued delivery of cooling water to the core. The actions, automatic or manual, that are currently in place at these plants to maintain long-term cooling remain unchanged with the application of the ASTRUM methodology (Reference 2).

Based on the ASTRUM Analysis results (see Table 2.8.5.6.3.2.1-2), it is concluded that MPS3 continues to maintain a margin of safety to the limits prescribed by 10 CFR 50.46.

2.8.5.6.3.2.1.5 References

1. Bajorek, S.M., et. al., 1998, “Code Qualification Document for Best-Estimate LOCA Analysis”, WCAP-12945-P-A, Volume 1, Revision 2 and Volumes 2 through 5, Revision 1, (Proprietary), and WCAP-14747 (Non-Proprietary).

2. Nissley, M.E., et.al., 2005, “Realistic Large Break LOCA Evaluation Methodology using the Automated Statistical TReatment of Uncertainty Method (ASTRUM)”, WCAP-16009-P-A.

3. “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors”, 10 CFR 50.46 and Appendix K of 10 CFR 50, Federal Register, Volume 39, Number 3, January 4, 1974.

4. Information Report from W.J. Dircks to the Commissioners, “Emergency Core Cooling System Analysis Methods”, SECY-83-472, November 17, 1983.

5. “Best-Estimate Calculations of Emergency Core Cooling System Performance”, Regulatory Guide 1.157, USNRC, May 1989.

6. “Qualifying Reactor Safety Margins: Application of Code Scaling Applicability and Uncertainty (CSAU) Evaluation Methodology to a Large Break Loss-of-Coolant-Accident”, B. Boyack, et. al., 1989.

Table 2.8.5.6.3.2.1-1
Major Plant Parameter Assumptions Used in the MPS3 Best-Estimate Large Break LOCA ASTRUM Analysis

Parameter	Value
Plant Physical Condition	
• SG Tube Plugging	$\leq$10%
Plant Initial Operating Conditions	
• Reactor Power	$\leq$3650 MWt
• Peaking Factors	$F_Q \leq 2.6$ $F_{\Delta H} \leq 1.65$
• Axial Power Distribution	See Figure 2.8.5.6.3.2.1-8
Fluid Conditions	
• T_{avg}	571.5 - 4 °F $\leq T_{avg} \leq$ 589.5 + 4 °F
• Pressurizer Pressure	2250 - 50 psia $\leq P_{RCS} \leq$ 2250 + 50 psia
• Reactor Coolant Flow	$\geq$ 90,800 gpm/loop
• Accumulator Temperature	80°F $\leq T_{ACC} \leq$ 120°F
• Accumulator Pressure	636 psia $\leq P_{ACC} \leq$ 694 psia
• Accumulator Water Volume	6618 gal $\leq V_{ACC} \leq$ 7030 gal
• Accumulator Boron Concentration	$\geq$ 2600 ppm
Accident Boundary Conditions	
• Single Failure Assumptions	Loss of one ECCS train
• Safety Injection Flow	Minimum
• Safety Injection Temperature	40°F $\leq T_{SI} \leq$ 100°F
• Safety Injection Initiation Delay Time	$\leq$ 40 sec (with offsite power) $\leq$ 45 sec (without offsite power)
• Containment Pressure	Bounded (minimum)

Table 2.8.5.6.3.2.1-2
MPS3 Best-Estimate Large Break LOCA Results

10 CFR 50.46 Requirement	Value	Criteria
95/95 PCT[a] (°F)	1,781	< 2,200
95/95 LMO[b] (%)	3.5	< 17
95/95 CWO[c] (%)	0.12	< 1
[a] Peak Cladding Temperature [b]Local Maximum Oxidation [c]Core-Wide Oxidation		

Table 2.8.5.6.3.2.1-3
MPS3 Best-Estimate Large Break LOCA Sequence of Events for Limiting PCT Case

Event	Time (sec)
Start of Transient	0.0
Safety Injection Signal	7.0
Accumulator Injection Begins	11.0
End of Blowdown	24.5
Bottom of Core Recovery	33.5
Accumulator Empty*	36.3
Safety Injection Begins	52.0
PCT Occurs	68.0
Core Quenched	430.0
End of Transient	500.0
*Accumulator Liquid Injection Ends	

Figure 2.8.5.6.3.2.1-1
MPS3 PCT vs. Effective Break Area

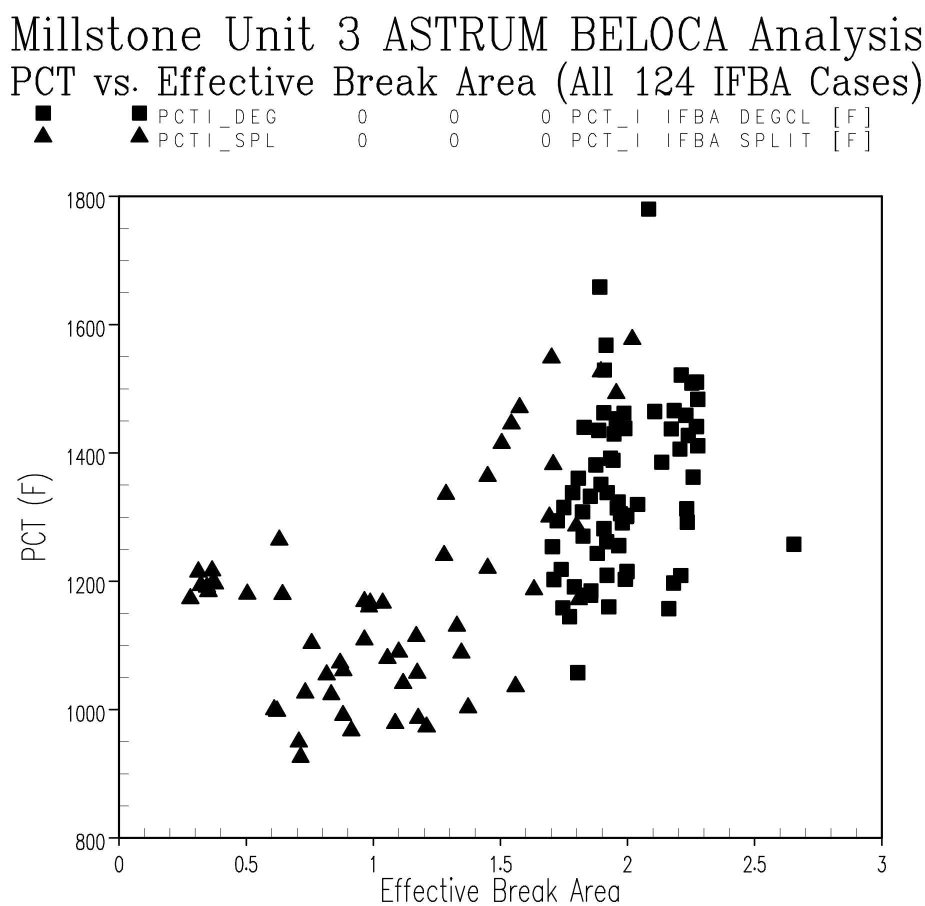


Figure 2.8.5.6.3.2.1-2
MPS3 BELOCA Analysis HOTSPOT Clad Temperature Transient at the Limiting Elevation for the Limiting PCT and LMO Case

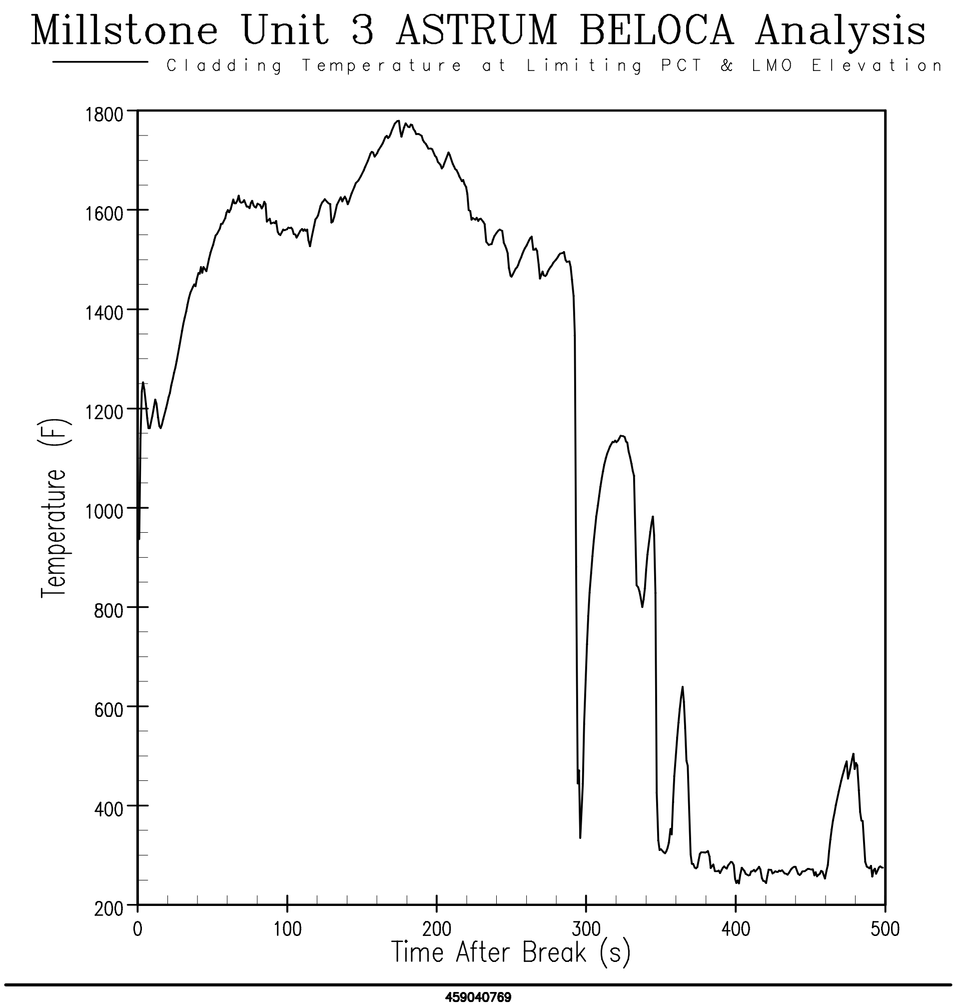


Figure 2.8.5.6.3.2.1-3
MPS3 BELOCA Analysis WCOBRA/TRAC Hot Assembly PCT Transient for the Limiting CWO Case

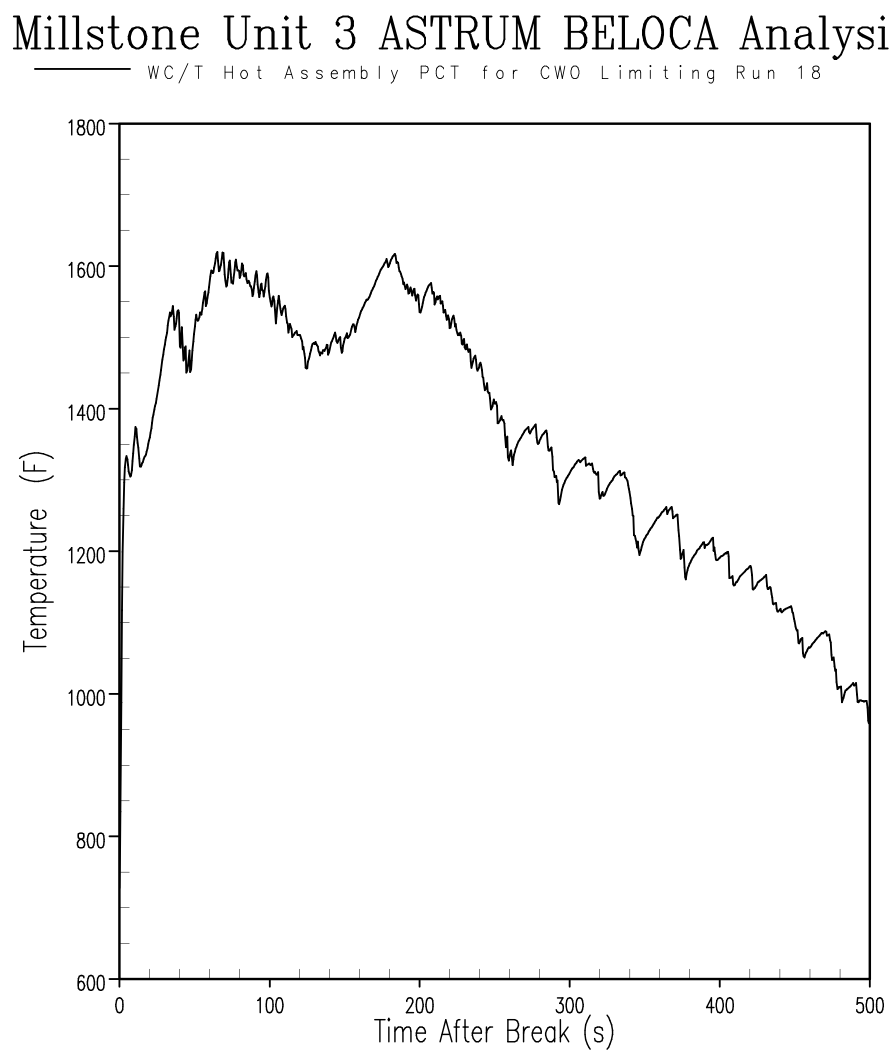


Figure 2.8.5.6.3.2.1-4
MPS3 Limiting PCT Case Pressurizer Pressure

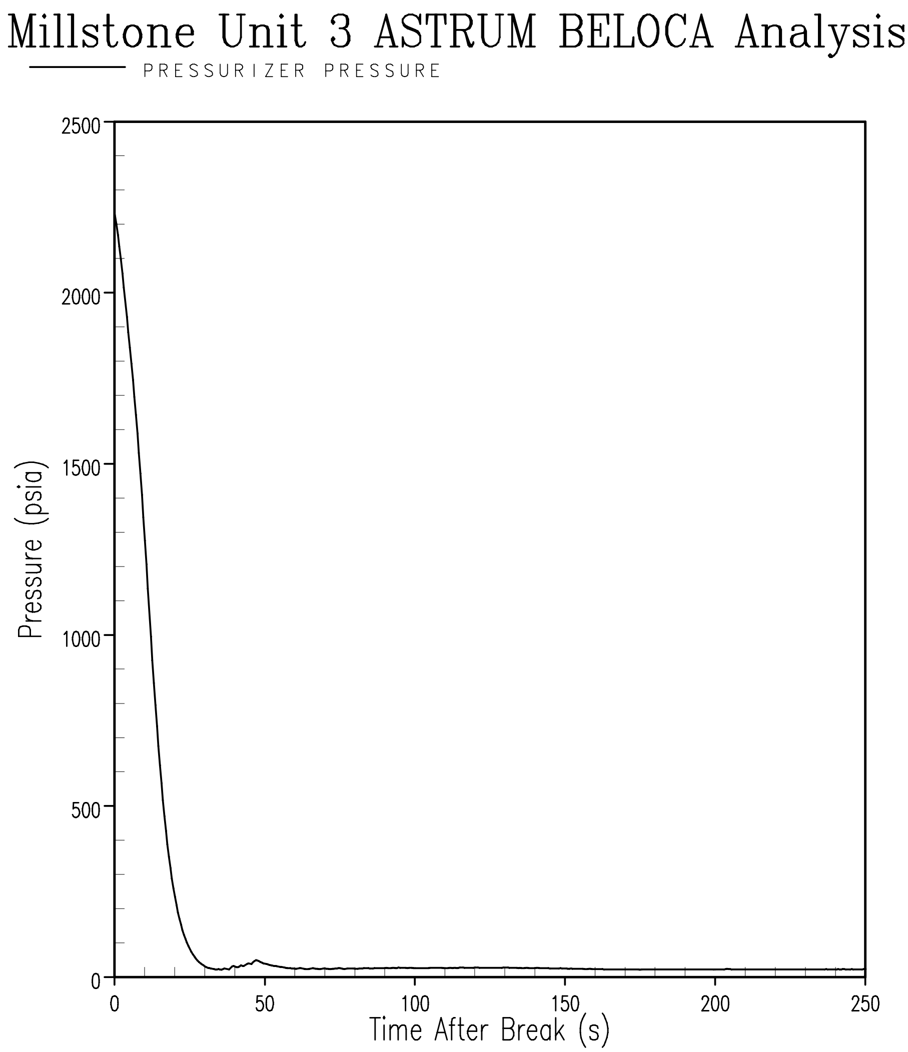


Figure 2.8.5.6.3.2.1-5
MPS3 Limiting PCT Case Vessel Side Break Flow

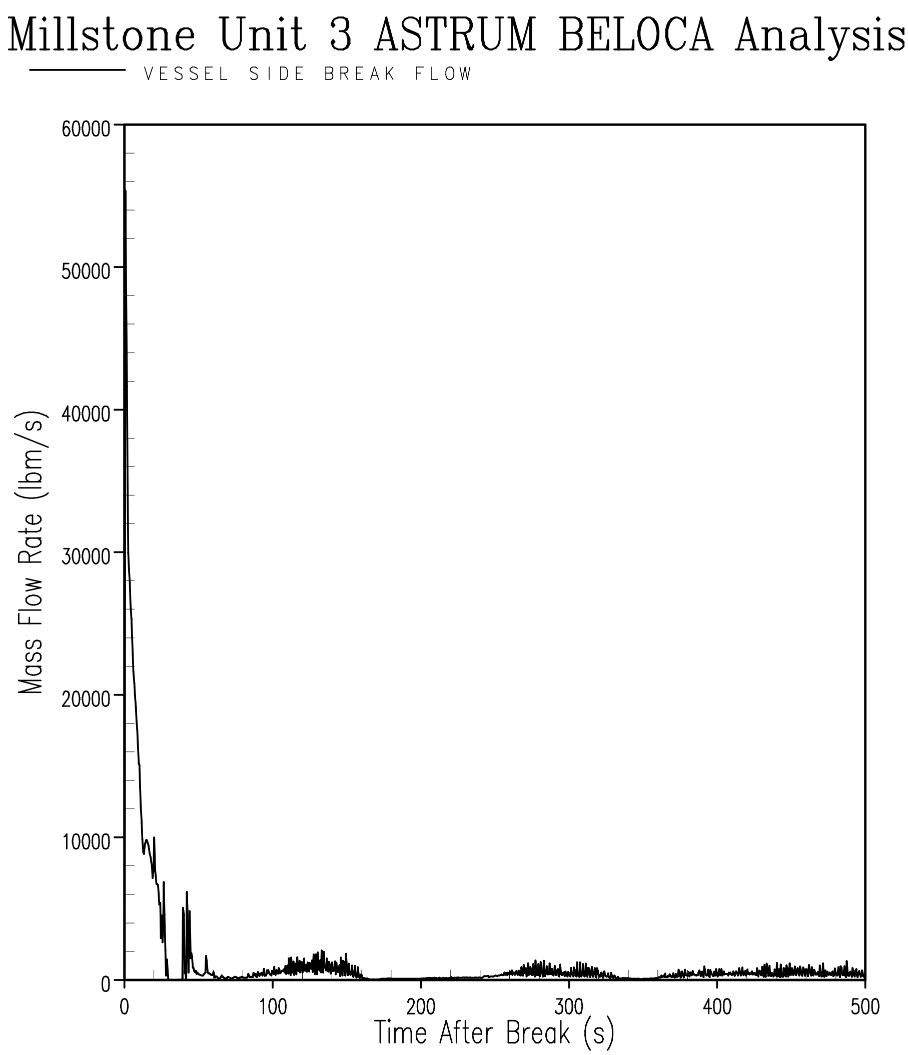


Figure 2.8.5.6.3.2.1-6 MPS3 Limiting PCT Case Loop Side Break Flow

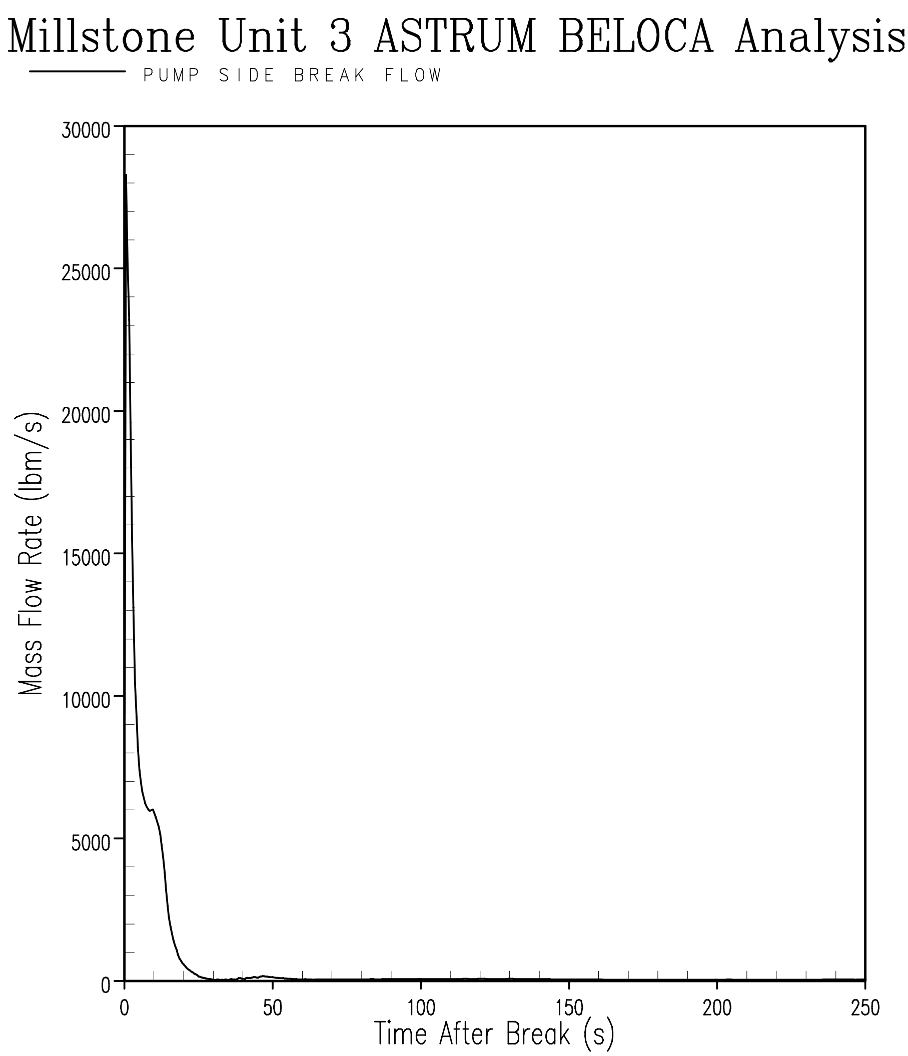


Figure 2.8.5.6.3.2.1-7
MPS3 Limiting PCT Case Broken and Intact Loop Pump Void Fraction

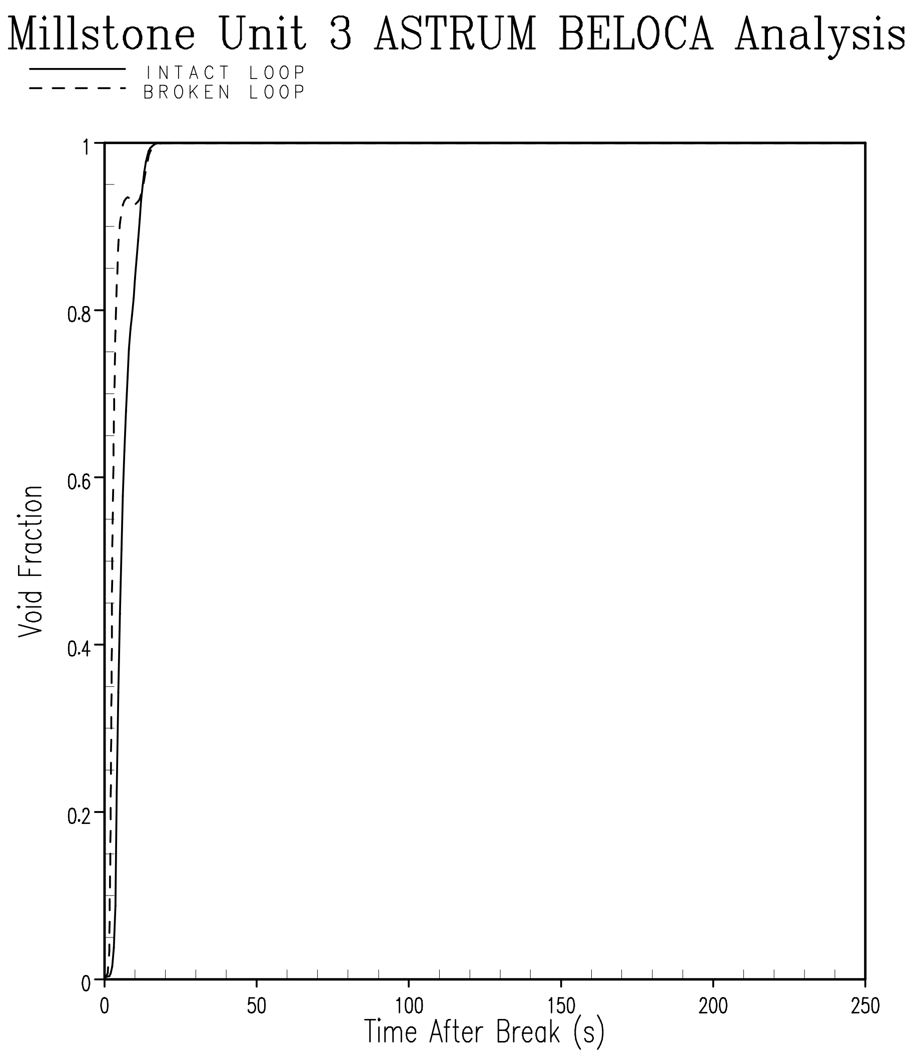


Figure 2.8.5.6.3.2.1-8
MPS3 Limiting PCT Case Hot Assembly Top Third of Core Vapor Flow

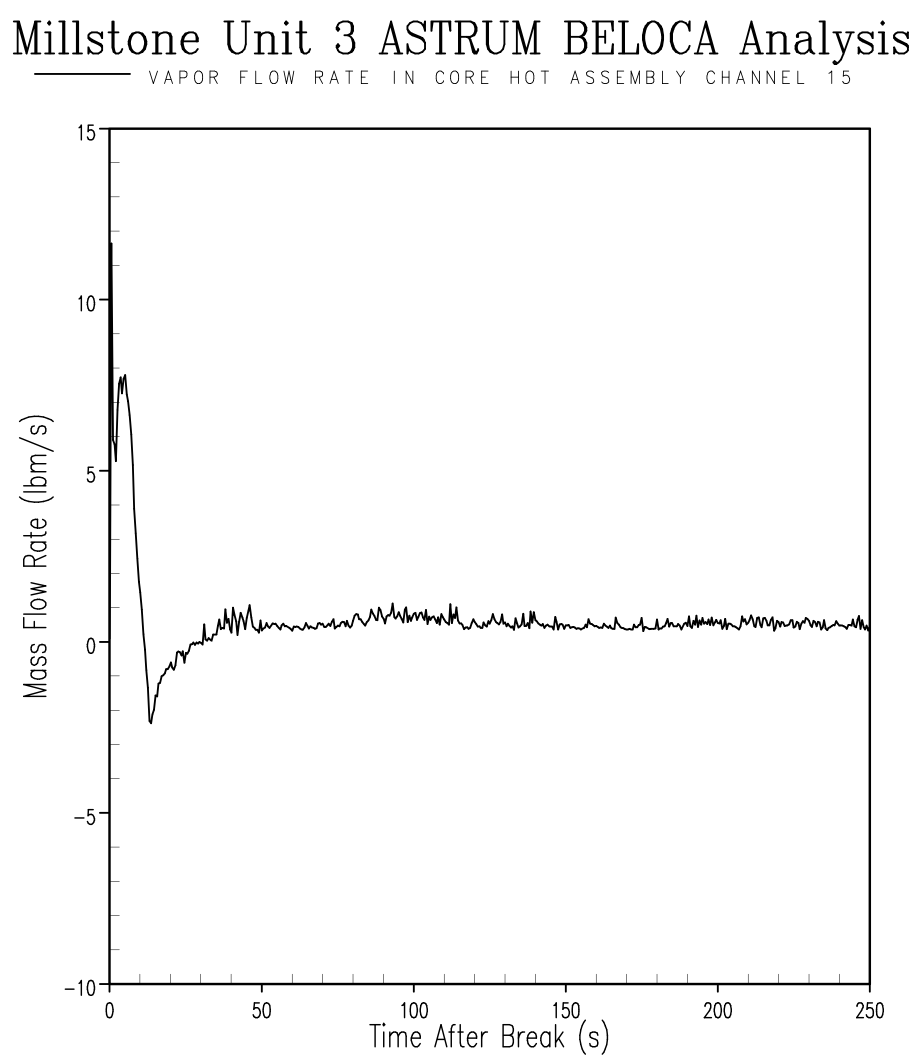


Figure 2.8.5.6.3.2.1-9
MPS3 Limiting PCT Case Loop 2 Accumulator Flow

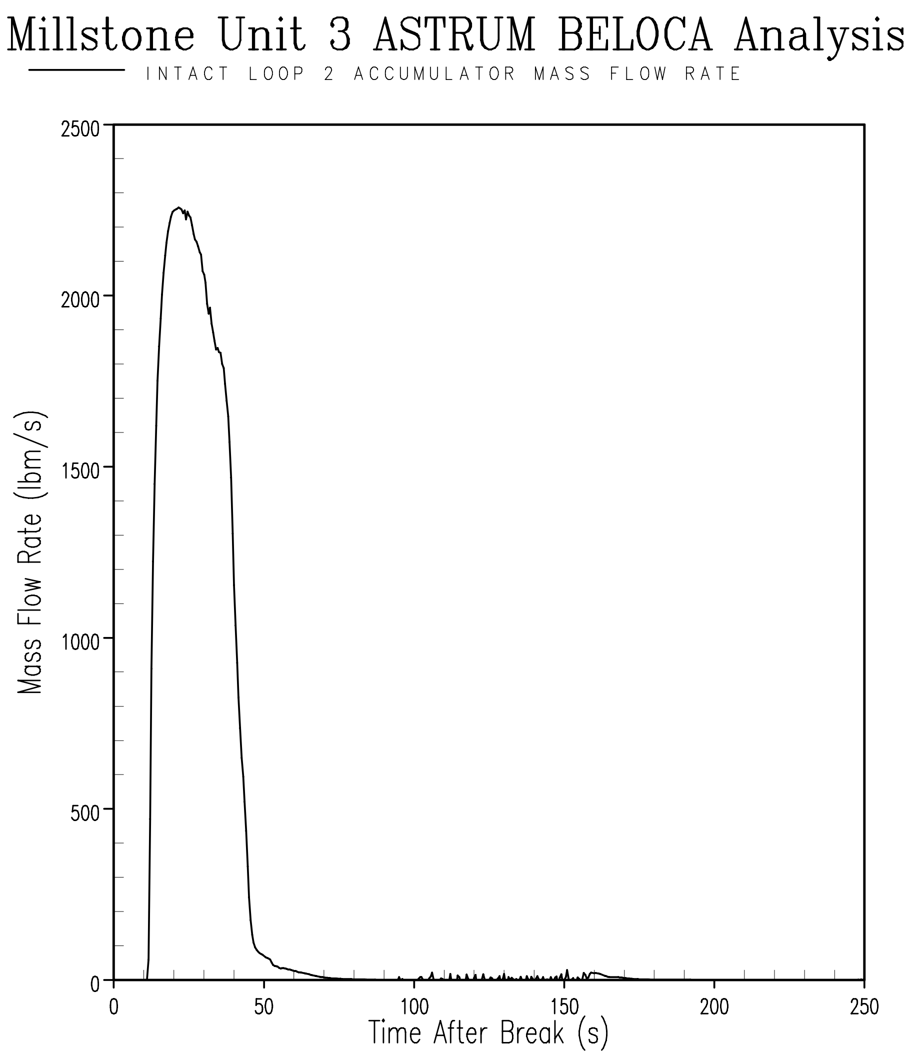


Figure 2.8.5.6.3.2.1-10
MPS3 Limiting PCT Case Intact Loop Safety Injection Flow

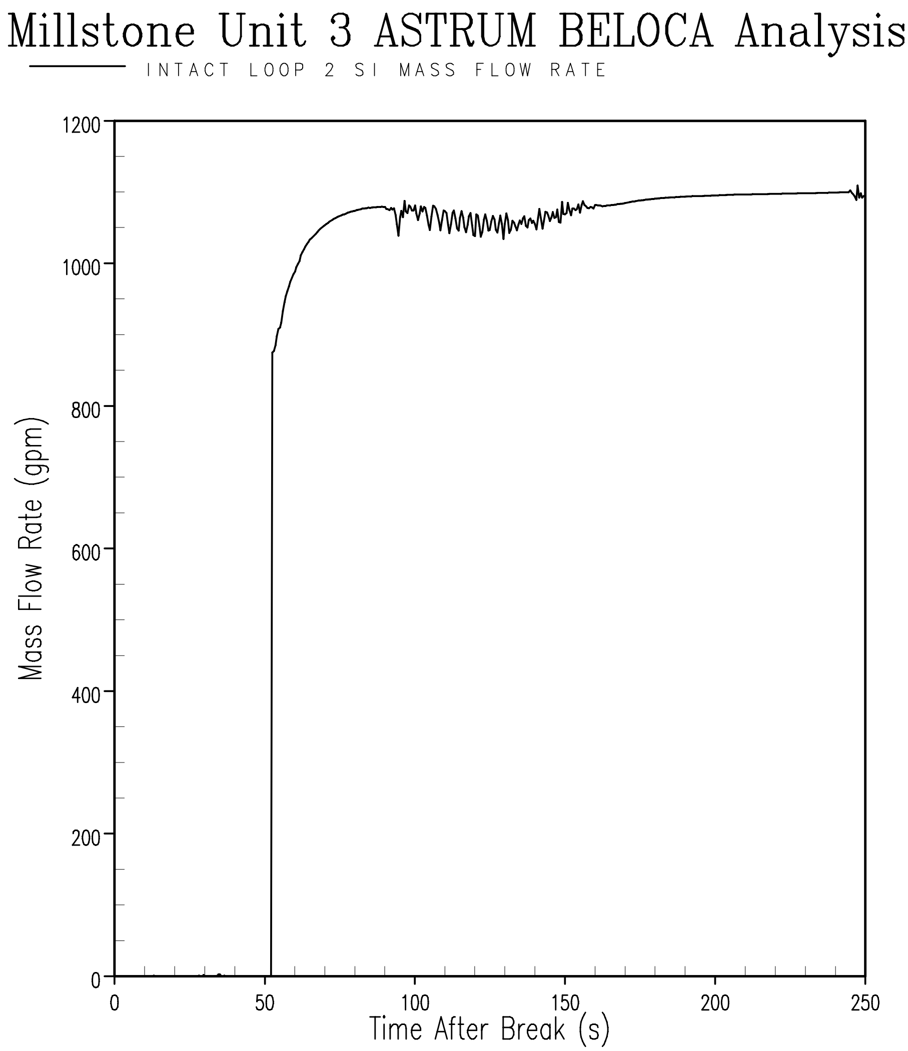


Figure 2.8.5.6.3.2.1-11
MPS3 Limiting PCT Case Lower Plenum Collapsed Liquid Level

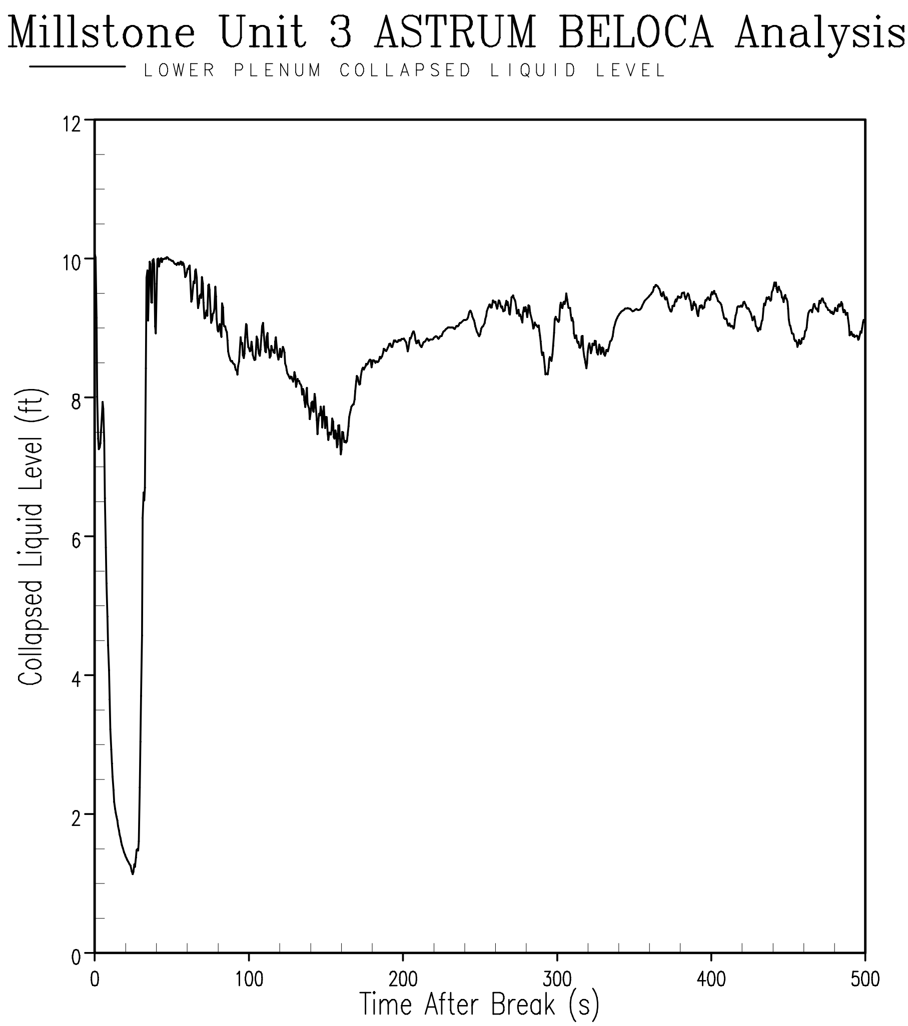


Figure 2.8.5.6.3.2.1-12
MPS3 Limiting PCT Case Loop 2 Downcomer Collapsed Liquid Level

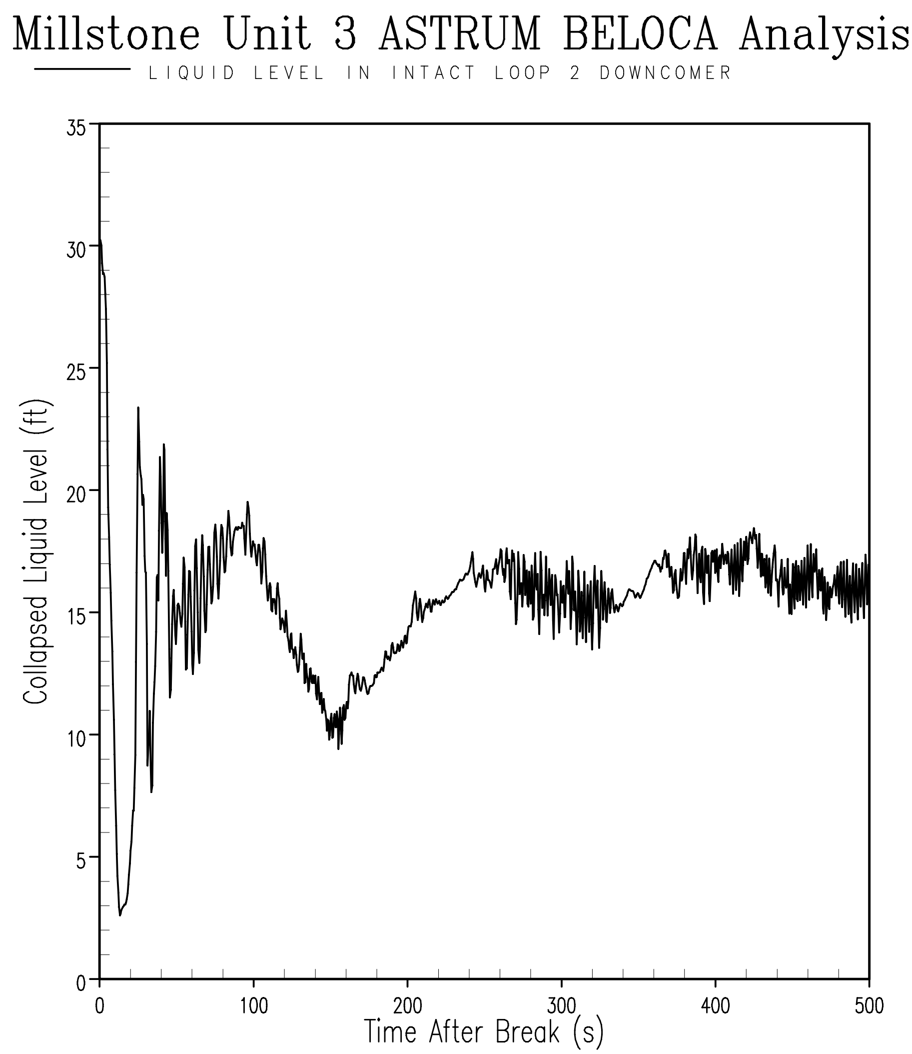


Figure 2.8.5.6.3.2.1-13
MPS3 Limiting PCT Case Core Average Channel Collapsed Liquid Level

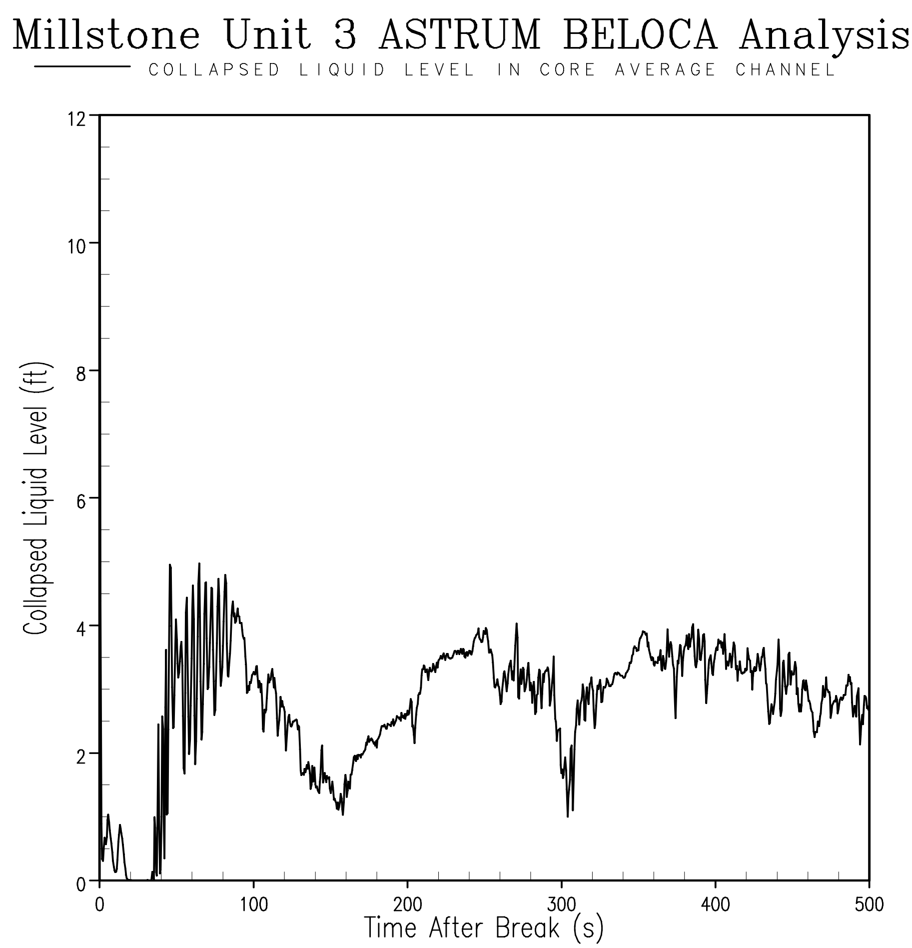


Figure 2.8.5.6.3.2.1-14 MPS3 Limiting PCT Case Vessel Water Mass

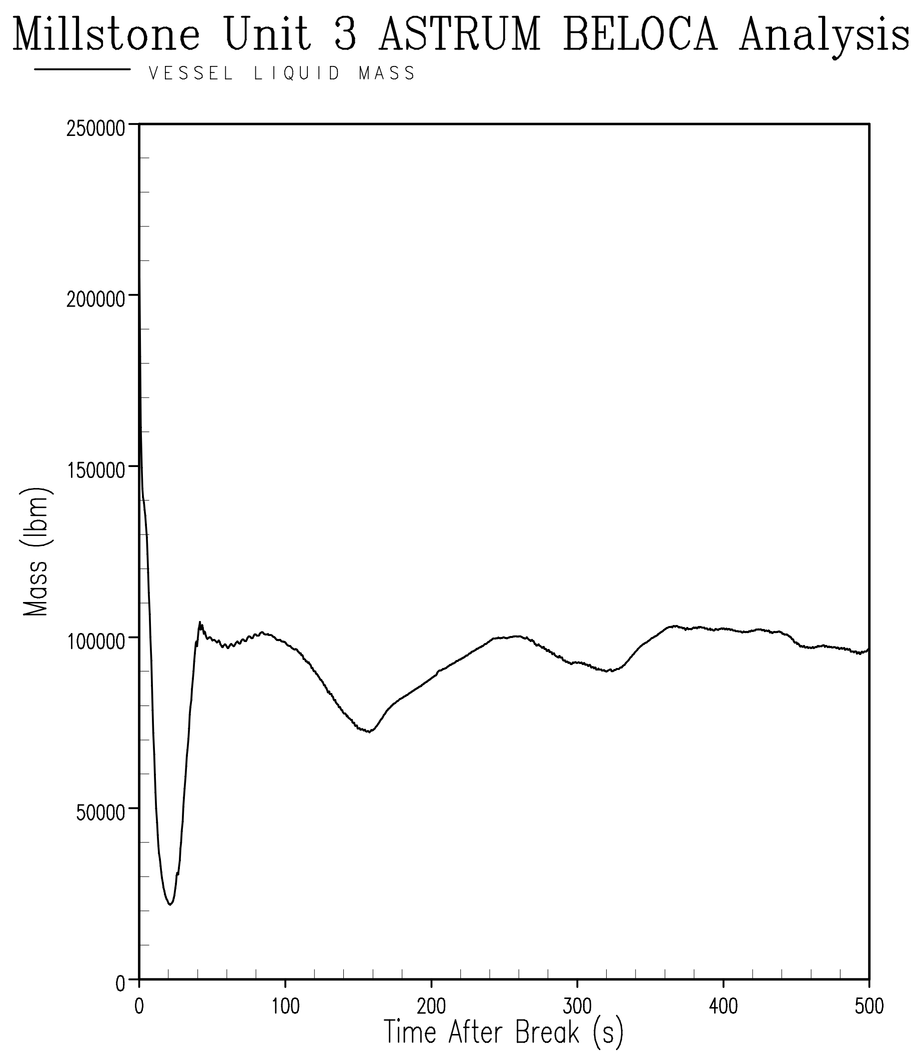


Figure 2.8.5.6.3.2.1-15
MPS3 Peak Cladding Temperature for all 5 Rods for the Limiting PCT Case

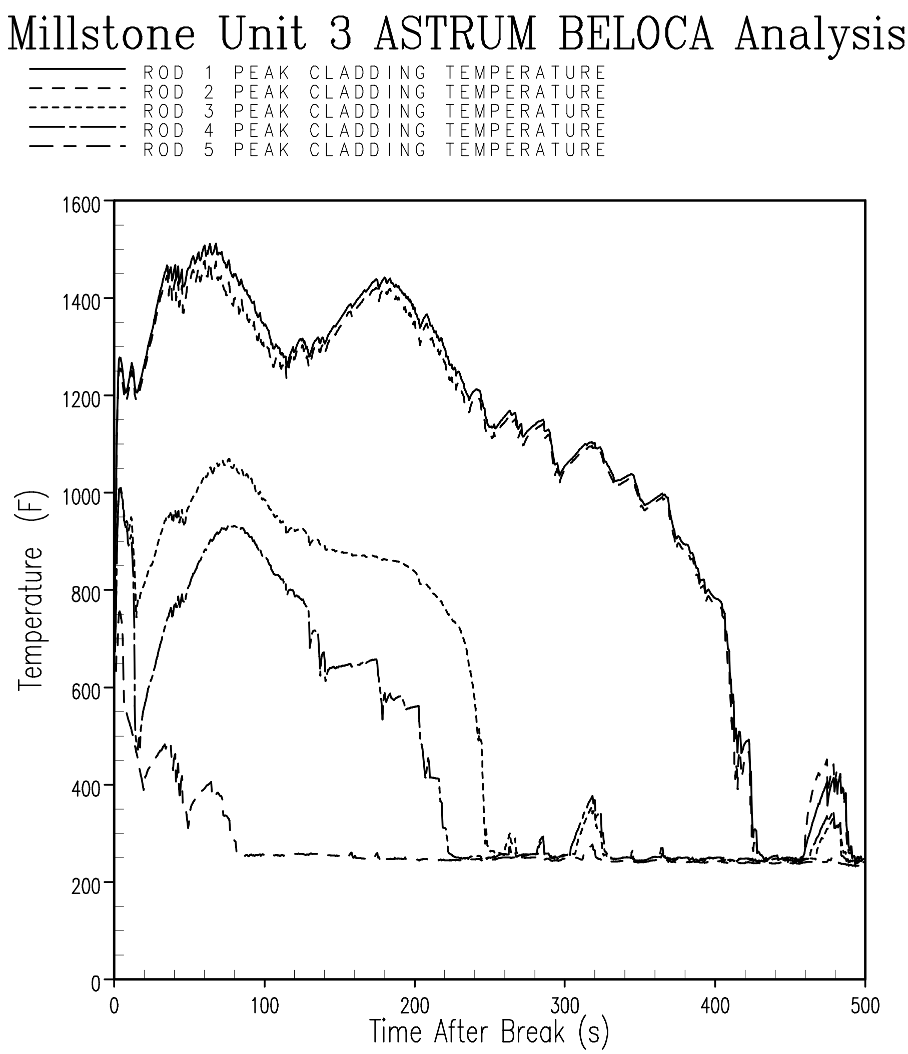


Figure 2.8.5.6.3.2.1-16
MPS3 PCT Location for Limiting PCT Case

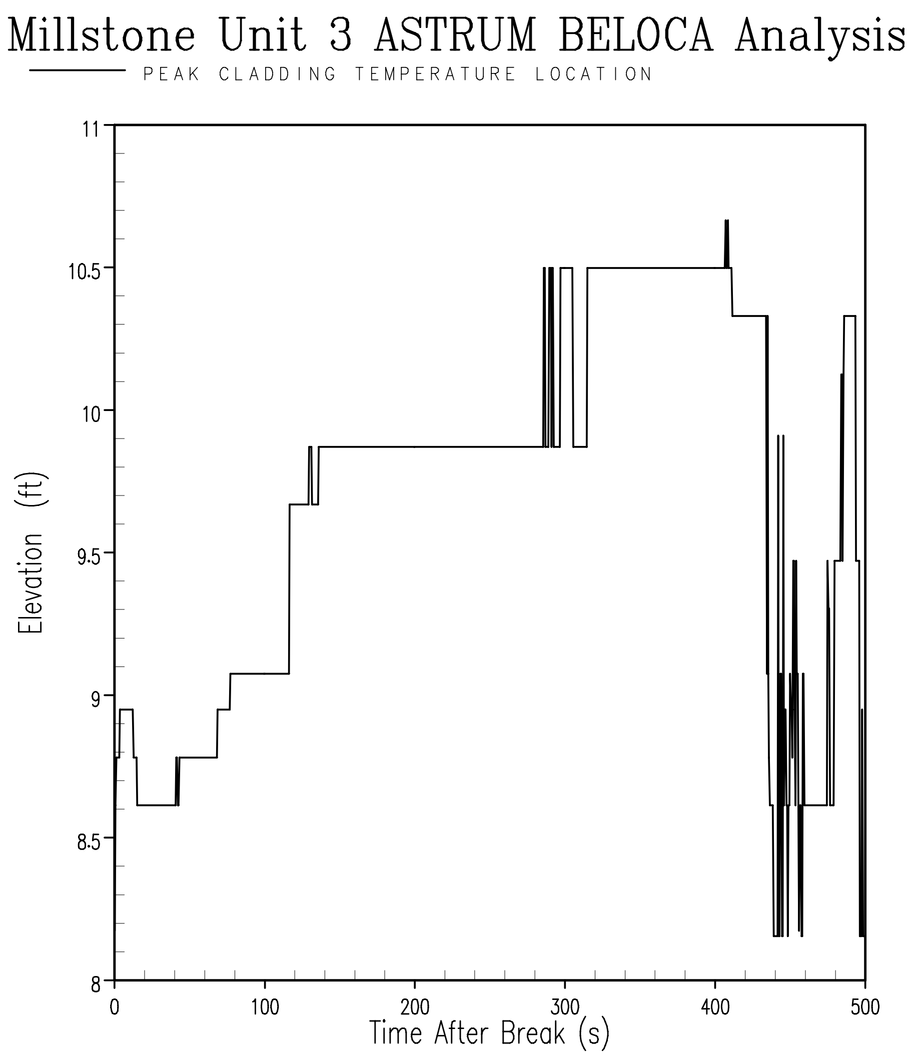


Figure 2.8.5.6.3.2.1-17
MPS3 WCOBRA/TRAC Containment Pressure for Limiting PCT Case

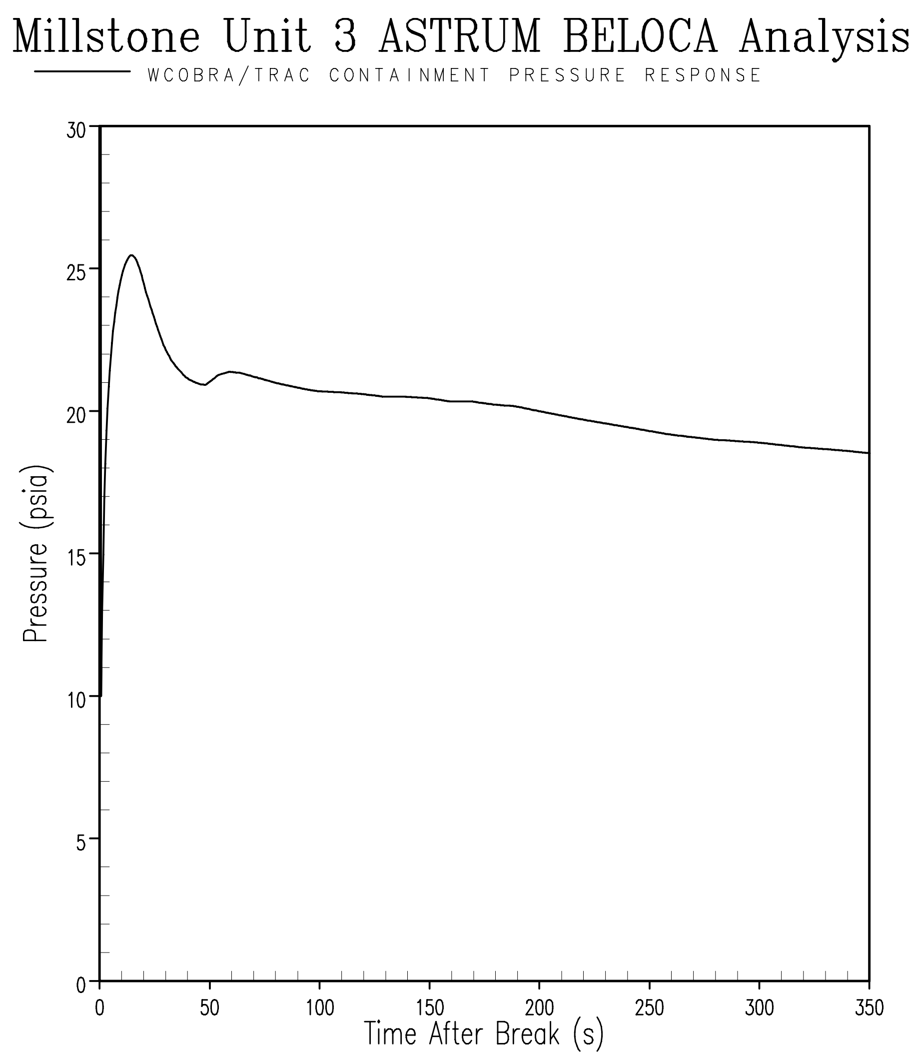
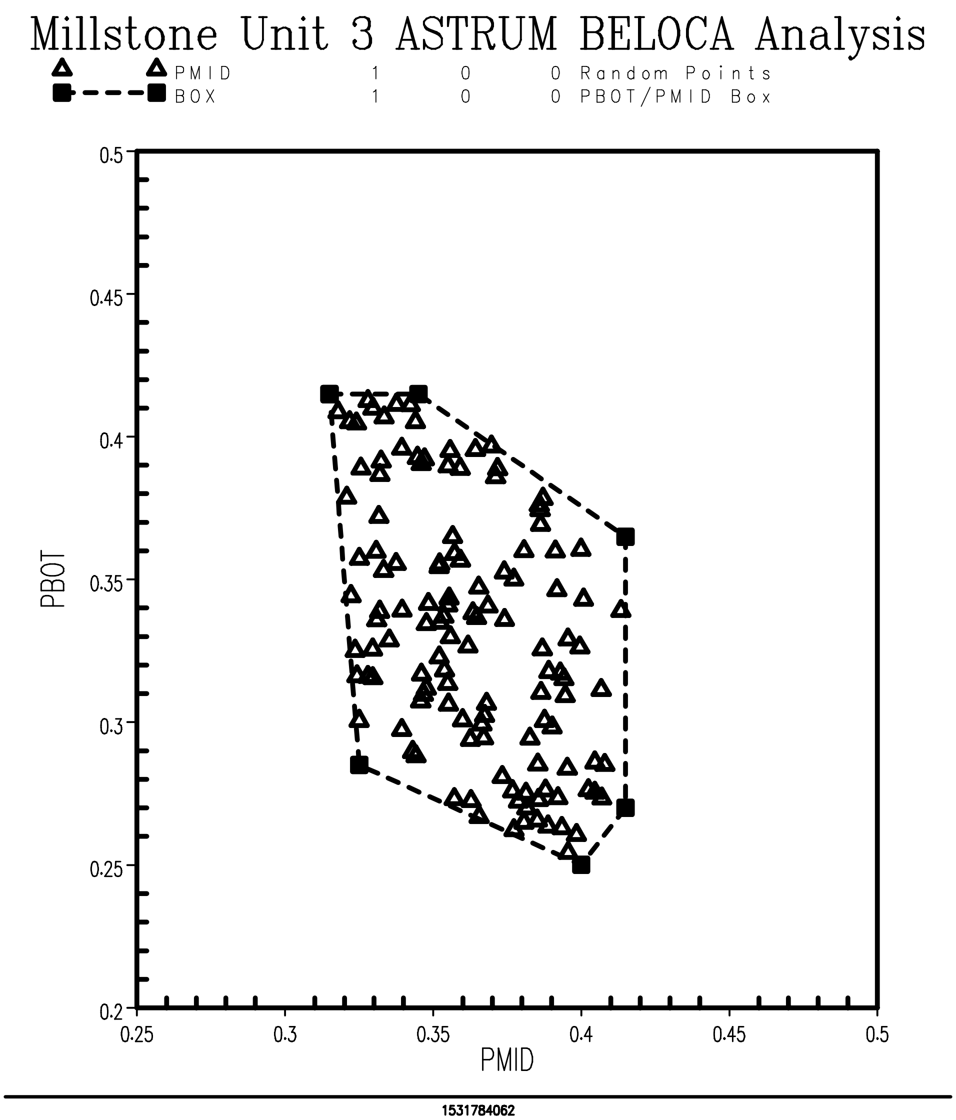


Figure 2.8.5.6.3.2.1-18
MPS3 BELOCA Analysis Axial Power Shape Operating Space Envelope



PBOT = integrated power fraction in the bottom third of the core

PMID = integrated power fraction in the middle third of the core

2.8.5.6.3.2.2 Small Break LOCA

A LOCA is defined as a rupture of the RCS piping or of any line connected to the system. The SBLOCA includes all postulated pipe ruptures with a total cross-sectional area less than 1.0 ft. The SBLOCAs analyzed in this section are for those breaks beyond the capability of a single charging pump resulting in the actuation of the ECCS. The analysis was performed to demonstrate conformance with the 10 CFR 50.46 requirements for the conditions associated with the SPU.

2.8.5.6.3.2.2.1 Input Parameters, Assumptions, and Acceptance Criteria

Key input parameters and assumptions are summarized in Tables 2.8.5.6.3.2.2-1 through 2.8.5.6.3.2.2-4. The SBLOCA analysis is based on MPS3 specific models.

The acceptance criteria for the SBLOCA analysis are specified in 10 CFR 50.46, as follows:

1. The calculated maximum fuel element cladding temperature shall not exceed 2,200°F.

2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core. (Note that this criterion is not addressed as part of the short-term SBLOCA analysis. Section 2.8.5.6.3.2.5, Post-LOCA Long Term Cooling, addresses this acceptance criterion.)

2.8.5.6.3.2.2.2 Description of Analyses and Evaluations

The SBLOCA analysis was performed for the MPS3 SPU using the 1985 Westinghouse SBLOCA Evaluation Model with NOTRUMP (NOTRUMP-EM) (Reference 1 through 3), including NRC approved changes to the methodology as described in References 4 and 5. Westinghouse obtained generic NRC approval of the NOTRUMP computer code's modeling capabilities and solution techniques (Reference 1) and the use of the NOTRUMP computer code for licensing applications (Reference 2) in 1985. NRC approval of additional modeling details (Reference 3), such as limiting break location was obtained in 1986. The NOTRUMP-EM was later revised (Reference 4) and granted generic NRC approval for an improved condensation model and related changes in safety injection modeling assumptions for safety injection to the RCS cold legs. Most recently, the NRC generically approved updates to the NOTRUMP-EM to include the ability to model annular fuel pellets (Reference 5) in the fuel rod heat-up calculations. The SBLOCA analysis was performed utilizing the above mentioned methodology at SPU conditions to generate the results presented herein. The methodology employed consists of first calculating the system thermal hydraulic response to the SBLOCA event using the NOTRUMP code. These results are then analyzed for their effect on the hot rod heat up using the SBLOCTA code to demonstrate that the peak cladding temperature, cladding oxidation and hydrogen generation are below their limiting values as defined by 10 CFR 50.46 (Reference 7).

For the MPS3 SPU SBLOCA analysis, a spectrum of cold leg breaks (1.5, 2, 3, 4 and 6 inch) as well as an accumulator line break of 8.75 inch has been analyzed which resulted in the 4 inch diameter break to be limiting. As a result of SBLOCA analysis submittals for various EPU and RSG programs, the NRC recently challenged Westinghouse on the coarseness of the standard NOTRUMP-EM break spectrum (i.e., 1.5, 2, 3, 4, and 6 inch). The Westinghouse position on the NOTRUMP-EM break spectrum was sent to the NRC in Reference 6 and included a proposed approach for future NOTRUMP-EM analyses. In any future applications of the NOTRUMP-EM, if any integer break size PCT is approximately equal to or greater than 1700°F, or if the PCT results are close to or greater than the corresponding LBLOCA PCT results, the analysis includes a refined break spectrum to assure 10 CFR 50.46 compliance. The results presented herein do not show PCTs approximately equal to or greater than 1700°F. Also, enough margin exists between the SBLOCA PCT and the LBLOCA PCT (see Section 2.8.5.6.3.2.1) to justify not including a refined break spectrum in this analysis.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal Application for the impact on the Small Break LOCA analysis. As stated in Section 2.8.5.6.3.2.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.6.3.2.2.3 Results

The results are shown in Figures 2.8.5.6.3.2.2-5 and 2.8.5.6.3.2.2-6. The peak cladding temperature is 1193°F, and the maximum local transient oxidation is 0.08 percent. The design limit 95 percent upper bound pre-transient oxidation value for each of the fuel designs included in the SPU cores is <17 percent. The actual upper bound values predicted for each of the fuel designs are well below this. Because the transient oxidation is so low, the sum of the transient and pre-transient oxidation remains below 17 percent at all times in life. The core-wide hydrogen generation remains well below the 10 CFR 50.46 acceptance limit of 1 percent, and the core geometry remains amenable to cooling. The transient results for the limiting PCT analysis case are provided in Figures 2.8.5.6.3.2.2-1 through 2.8.5.6.3.2.2-14. The results presented herein meet the acceptance criteria noted in Section 2.8.5.6.3.2.2.1.

The MPS3 current licensing basis requirements with respect to GDC-4 are met by the SBLOCA analysis in that core coolability is maintained as demonstrated in Section 2.8.1, Fuel System Design. The MPS3 current licensing basis requirements with respect to GDC-27 are met for SBLOCA in that adequate poison is added by the ECCS to ensure the core remains subcritical as demonstrated in Section 2.8.5.6.3.2.4 Post-LOCA Subcriticality. The MPS3 current licensing basis requirements with respect to GDC-35 are met for SBLOCA since the 10 CFR 50.46 acceptance criteria are met by this analysis for the short term accident ECCS performance in conjunction with the long term cooling capability demonstrated in Section 2.8.5.6.3.2.5, Post-LOCA Long Term Cooling.

2.8.5.6.3.2.2.4 References

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

2. WCAP-10054-P-A, “Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code,” Lee, N., et al., August 1985.

3. WCAP-11145-P-A, “Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code,” Rupprecht, S. D., et al., October 1986.

4. WCAP-10054-P-A, Addendum 2, Revision 1, “Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model,” Thompson, C. M., et al., July 1997.

5. WCAP-14710-P-A, “1-D Heat Conduction Model for Annular Fuel Pellets,” Shimeck, D. J., May 1998.

6. LTR-NRC-06-44, “Transmittal of LTR-NRC-06-44 NP-Attachment, “Response to NRC Request for Additional Information on the Analyzed Break Spectrum for the Small Break Loss of Coolant Accident (SBLOCA) NOTRUMP Evaluation Model (NOTRUMP EM), Revision 1”, (Non-Proprietary),” Gresham, J. A., July 2006.

7. “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors,” 10 CFR 50.46.

Table 2.8.5.6.3.2.2-1
SBLOCA Input Assumptions and Initial Conditions

A.	Core Parameters	
	Analyzed Core Power Level	3650 MWt
	Calorimetric Uncertainty	1.02%
	Fuel Type	RFA/RFA-2 with IFMS
	Total Core Peaking Factor, F_Q	2.60
	Channel Enthalpy Rise Factor, F_H	1.65
	Axial Offset	20%
	K(z) Limit	2 line segment, 1.0 from 0.0 ft to 6.0 ft, 1.0 to 0.925 from 6.0 ft to 12.0 ft
B.	Reactor Coolant System	
	Thermal Design Flow	363200 gpm
	Nominal Vessel Average Temperature (Range)	571.5°F - 589.5°F
	Pressurizer Pressure	2250 psia
	Pressurizer Pressure Uncertainty	50 psi
C.	Reactor Protection System	
	Reactor Trip Setpoint	1700 psia
	Reactor Trip Signal Processing Time (Includes Rod Drop Time)	4.7 seconds
D.	Auxiliary Feedwater System	
	Maximum AFW Temperature	120°F
	Minimum AFW Flow Rate	61.625 gpm/SG
	Initiation Signal	SI Signal
	AFW Delivery Delay Time	60 seconds
E.	Steam Generators	
	Steam Generator Tube Plugging	10%
	MFW Isolation Signal	SI Signal
	MFW Delivery Delay Time	7 seconds
	Feedwater Temperature	390.0°F- 445.3°F

Table 2.8.5.6.3.2.2-1
SBLOCA Input Assumptions and Initial Conditions

	Steam Generator Safety Valve Flow Rates	Tables 2.8.5.6.3.2.2-2
F.	Safety Injection	
	Limiting Single Failure	Loss of one Emergency Diesel Generator
	Maximum SI Water Temperature	100°F
	SI Delay Time	40 seconds
	Safety Injection Flow Rates	Tables 2.8.5.6.3.2.2-3 and 2.8.5.6.3.2.2-4
G.	Accumulators	
	Water/Gas Temperature	120 °F
	Initial Accumulator Water Volume	900 ft^3
	Minimum Cover Gas Pressure	609.4 psia
H.	RWST Draindown Input	
	Maximum Containment Spray Flow	6500 gpm
	Minimum Usable RWST Volume	598,000 gal
	Maximum Delay Time for Switchover to Cold Leg Recirculation	0 seconds
	Minimum SI Flow Rate During Switchover	No SI Interruption
	Minimum SI Flow Rate After Switchover	No change in charging/IHSI from injection phase; no RHR after switchover.
	Maximum SI Water Temperature After Switchover to Cold Leg Recirculation Signal is Generated	212°F

Table 2.8.5.6.3.2.2-2
Steam Generator Safety Valve Flows per Steam Generator

MSSV	Set Pressure (psig)	Uncertainty (%)	Accumulation (%)	Rated Flow at Full Open Pressure (lbm/hr)
1	1185	3	3	893160
2	1195	3	3	900607
3	1205	3	3	908055
4	1215	3	3	915502
5	1225	3	3	922950

Table 2.8.5.6.3.2.2-3
Safety Injection Flows vs. Pressure, Minimum Safeguards, Spill to RCS Pressure
(Breaks < 8.75 in. diameter)

RCS Pressure (psia)	Intact Loop Injection Flow (gpm)	Broken Loop Injection Flow (gpm)
14.7	719.8	259.0
114.7	697.7	251.1
214.7	675.1	242.9
314.7	650.4	234.1
414.7	625.0	225.0
514.7	598.9	215.6
614.7	570.9	205.6
714.7	541.4	195.1
814.7	509.9	183.7
914.7	476.0	171.6
1014.7	438.7	158.1
1114.7	393.9	142.2
1214.7	334.1	120.7
1314.7	248.8	90.3
1414.7	173.4	63.4
1514.7	162.9	59.5
1614.7	152.1	55.6
1714.7	138.9	50.8
1814.7	125.1	45.7
1914.7	111.0	40.6
2014.7	96.9	35.4
2114.7	84.0	30.7
2214.7	74.4	27.2
2314.7	64.8	23.7
2414.7	55.2	20.1
2482.7	0.0	0.0

Table 2.8.5.6.3.2.2-4
Safety Injection Flows vs. Pressure, Minimum Safeguards, Spill to Containment Pressure (Breaks ≥ 8.75 in. diameter)

RCS Pressure (psia)	Intact Loop Injection Flow (gpm)	Broken Loop Spilling Flow (gpm)
14.7	3453.4	1340.6
34.7	2884.7	1716.9
54.7	2290.5	2079.6
74.7	1768.3	2359.1
94.7	1353.8	2533.5
114.7	818.0	2732.0
134.7	686.2	2777.1
154.7	680.1	2778.4
174.7	673.9	2779.9
194.7	667.8	2781.4
214.7	661.7	2782.9
314.7	629.0	2791.2
414.7	595.2	2799.4
514.7	560.1	2807.5
614.7	523.9	2815.8
714.7	484.7	2823.8
814.7	443.5	2831.9
914.7	394.5	2870.0
1014.7	339.3	2880.3
1114.7	276.2	2891.1
1214.7	194.4	2902.4
1314.7	134.5	2909.6
1414.7	118.2	2915.6
1514.7	101.0	2919.4
1614.7	83.3	2923.4
1714.7	64.8	2927.5

Table 2.8.5.6.3.2.2-4
Safety Injection Flows vs. Pressure, Minimum Safeguards, Spill to Containment Pressure (Breaks ≥ 8.75 in. diameter)

RCS Pressure (psia)	Intact Loop Injection Flow (gpm)	Broken Loop Spilling Flow (gpm)
1814.7	43.5	2931.6
1914.7	16.3	2936.0
2014.7	0.0	2939.4
2114.7	0.0	2939.4
Note that the above flows are applicable before switchover to recirculation and include RHR flows.		

Table 2.8.5.6.3.2.2-5
NOTRUMP Transient Results

Event (sec)	1.5-inch (3)	2.0-inch	3.0-inch	4.0-inch	6.0-inch	8.75-inch (3)
Transient Initiated	0.0	0.0	0.0	0.0	0.0	0.0
Reactor Trip Signal	174	180	60	32	16	10
Safety Injection Signal	184	191	70	41	20	11
Safety Injection Begins (1)	224	231	110	81	60	51
Loop Seal Clearing Occurs (2)	2152	1092	422	255	127	18
Top of Core Uncovered	N/A	2478	705	637	429	N/A
Accumulator Injection Begins	N/A	N/A	1919	887	386	176 (4)
Top of Core Recovered	N/A	4290	2389	1550	445	N/A
RWST Low Level	5210	5164	N/A	N/A	N/A	N/A

1. Safety Injection begins 40 seconds (SI delay time) after the safety injection signal.
2. Loop seal clearing is considered to occur when the broken loop seal vapor flow rate is sustained above 1lbm/sec.
3. There is no core uncovery for the 1.5-inch break case and minimal core uncovery for the 8.75-inch break case.
4. For the 8.75-inch case, the broken loop (BL) accumulator is spilling to containment and the accumulator injection time listed here is only the intact loop (IL) accumulator injection time.

Table 2.8.5.6.3.2.2-6
Beginning of Life (BOL) Rod Heatup Results

Event (sec)	1.5-inch(1)	2.0-inch	3.0-inch	4.0-inch	4.0-inch with Annular Pellets	6.0-inch	8.75-inch(1)
Peak Cladding Temperature, °F	N/A	922	1128	1193	1193	527	N/A
PCT Time, sec		3340	1646	971	971	438	
PCT Elevation, ft		11.00	11.25	11.25	11.25	11.50	
Burst Time, sec(2)		N/A	N/A	N/A	N/A	N/A	
Burst Elevation, ft(2)		N/A	N/A	N/A	N/A	N/A	
Maximum Hot Rod ZrO_2, %		0.01	0.08	0.05	0.05	0.0	
Maximum Hot Rod ZrO_2 Elevation, ft		11.00	11.25	11.25	11.25	11.50	
Hot Rod Average ZrO_2, %		0.0	0.01	0.01	0.01	0.0	

1. There is no core uncovery for the 1.5-inch break case and minimal core uncovery for the 8.75-inch break case, therefore rod heatup calculations were not performed.
2. None of the SBLOCTA calculations exhibited rod burst (hot rod or hot assembly average rod).

Figure 2.8.5.6.3.2.2-1
Pressurizer Pressure 4-inch Break

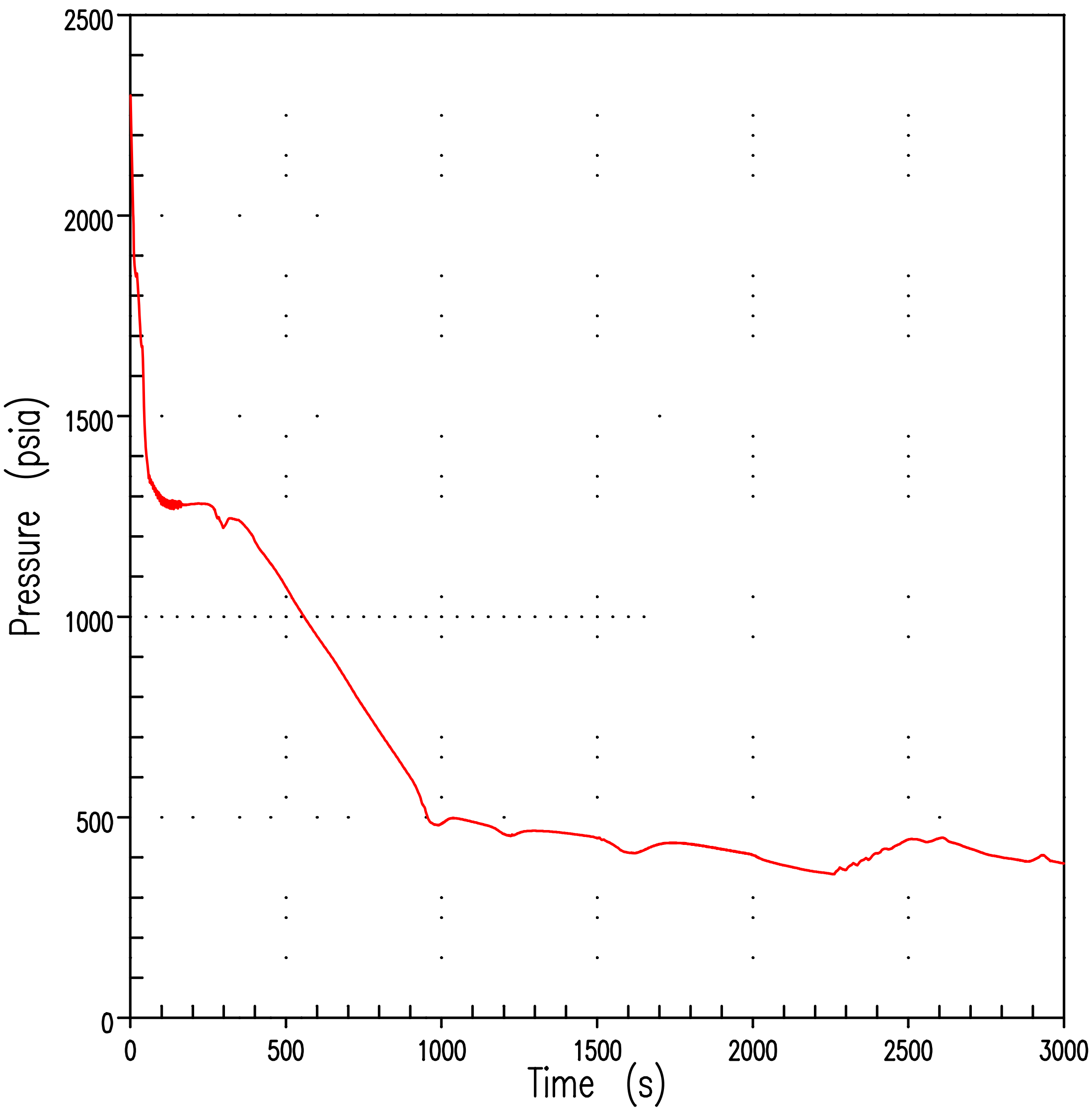


Figure 2.8.5.6.3.2.2-2
Core Mixture Level 4-inch Break

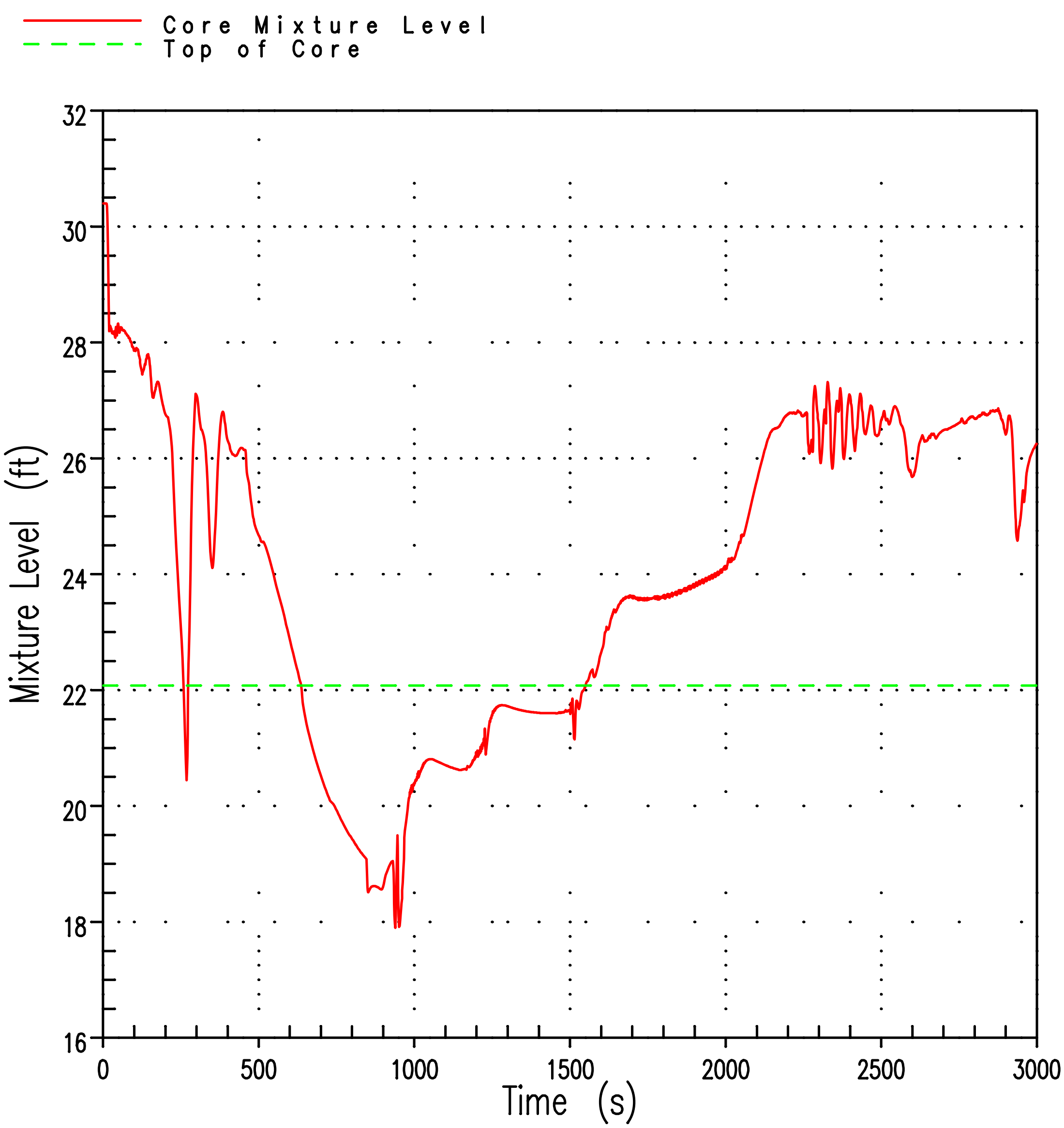


Figure 2.8.5.6.3.2.2-3
Broken Loop and Intact Loop Pumped SI Flow Rate
4-inch Break

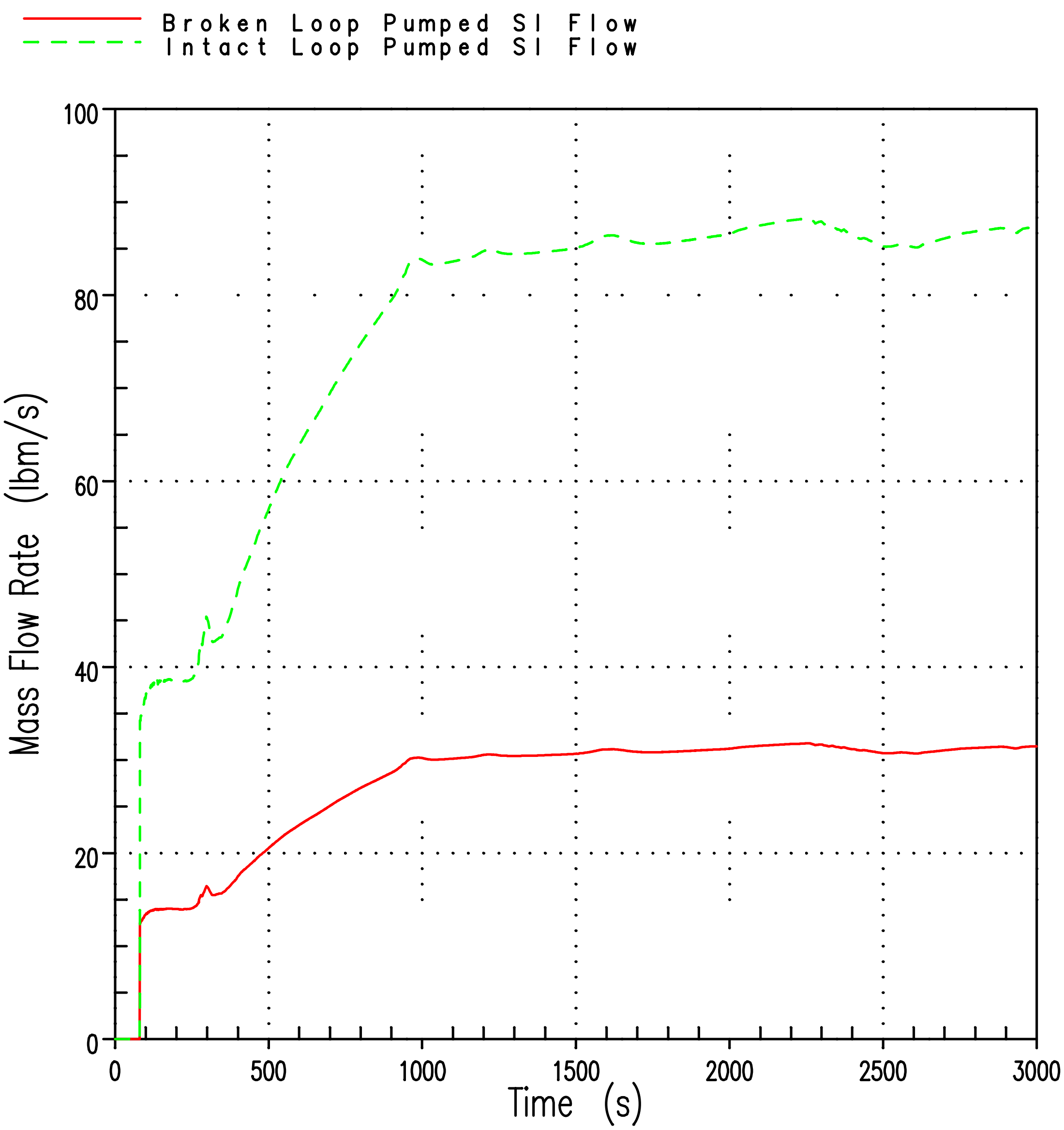


Figure 2.8.5.6.3.2.2-4
Cladding Temperature at PCT Elevation 4-inch Break

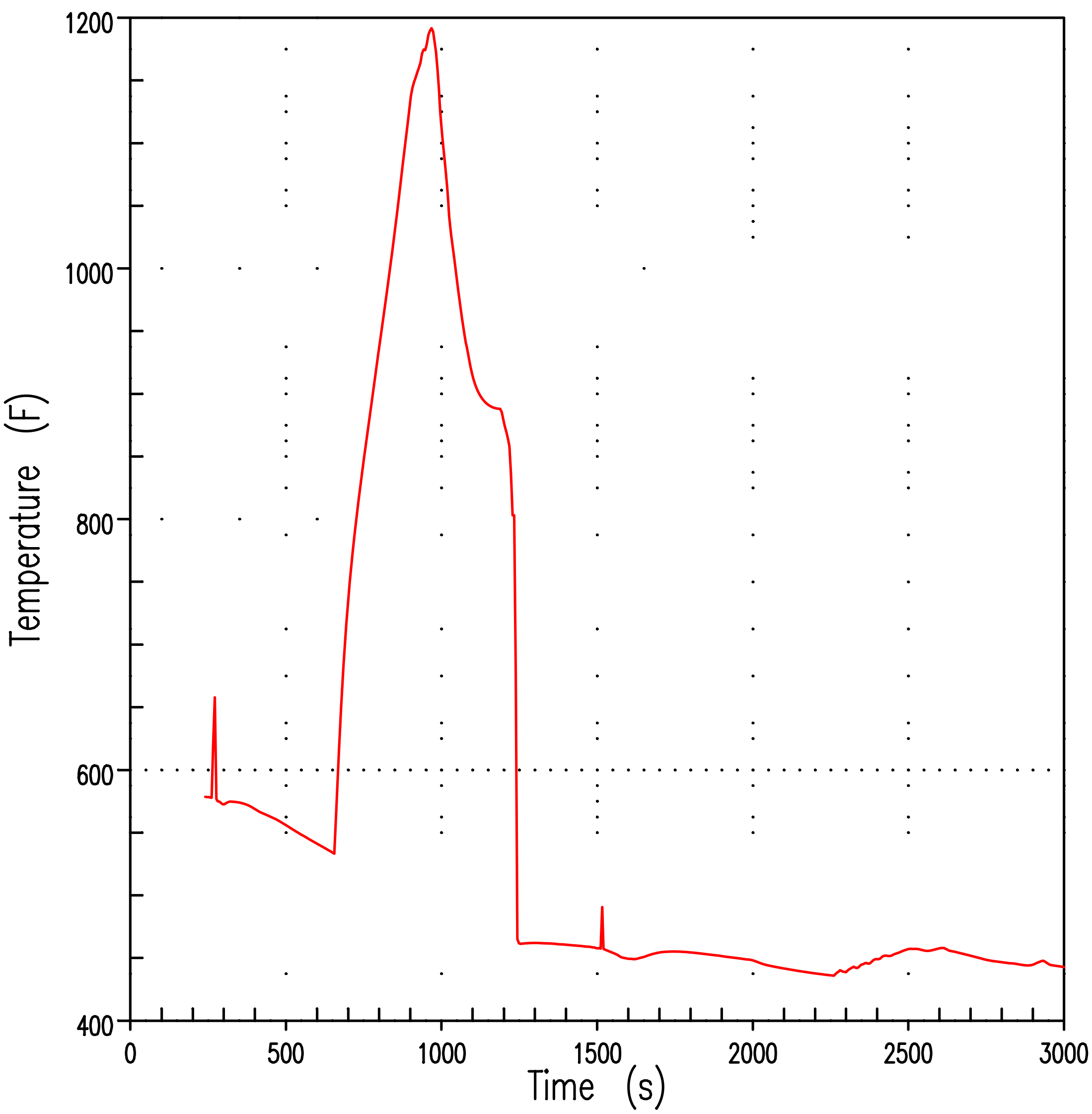


Figure 2.8.5.6.3.2.2-5
Core Exit Vapor Flow Rate 4-inch Break

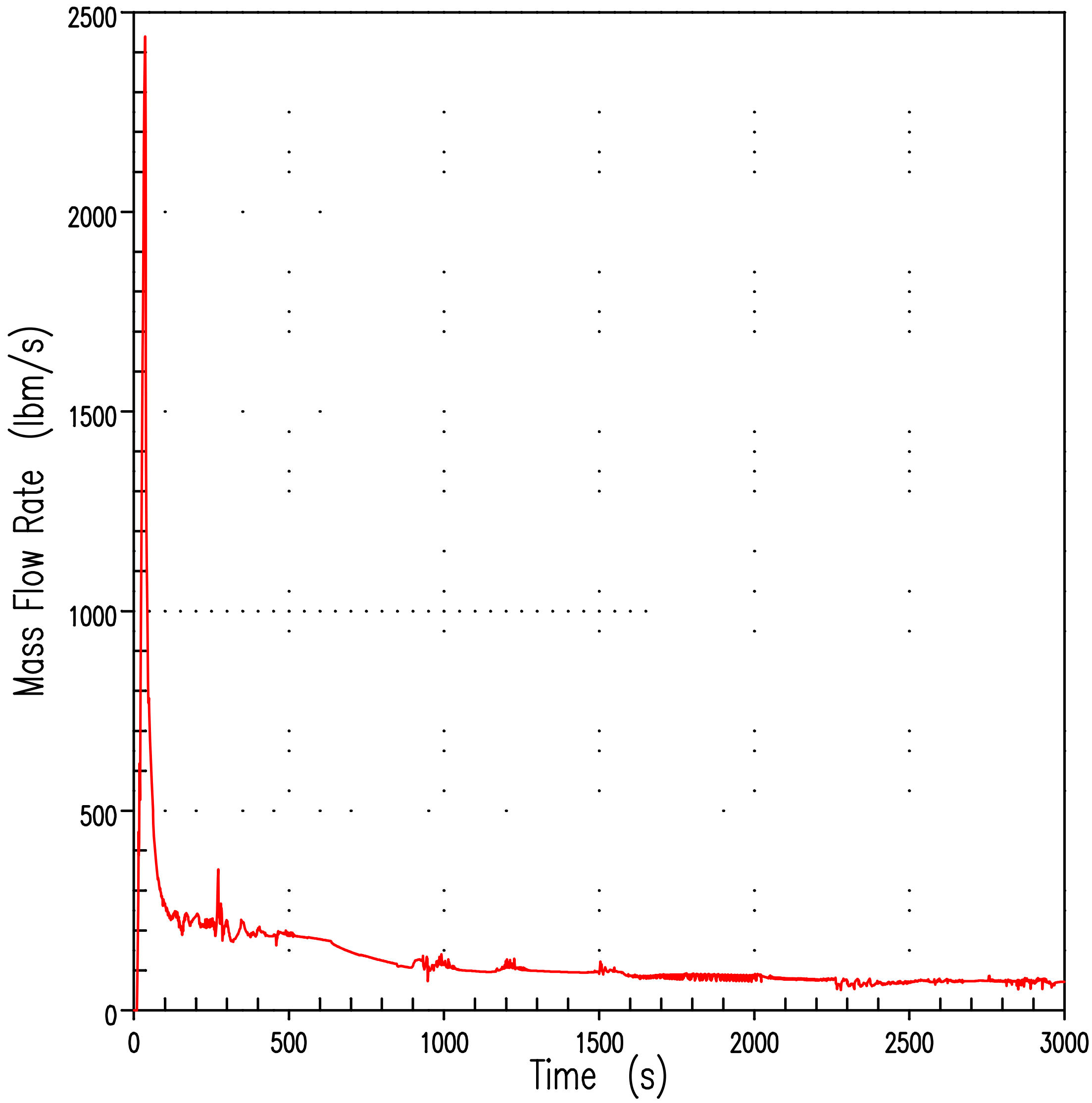


Figure 2.8.5.6.3.2.2-6
Core Power 4-inch Break

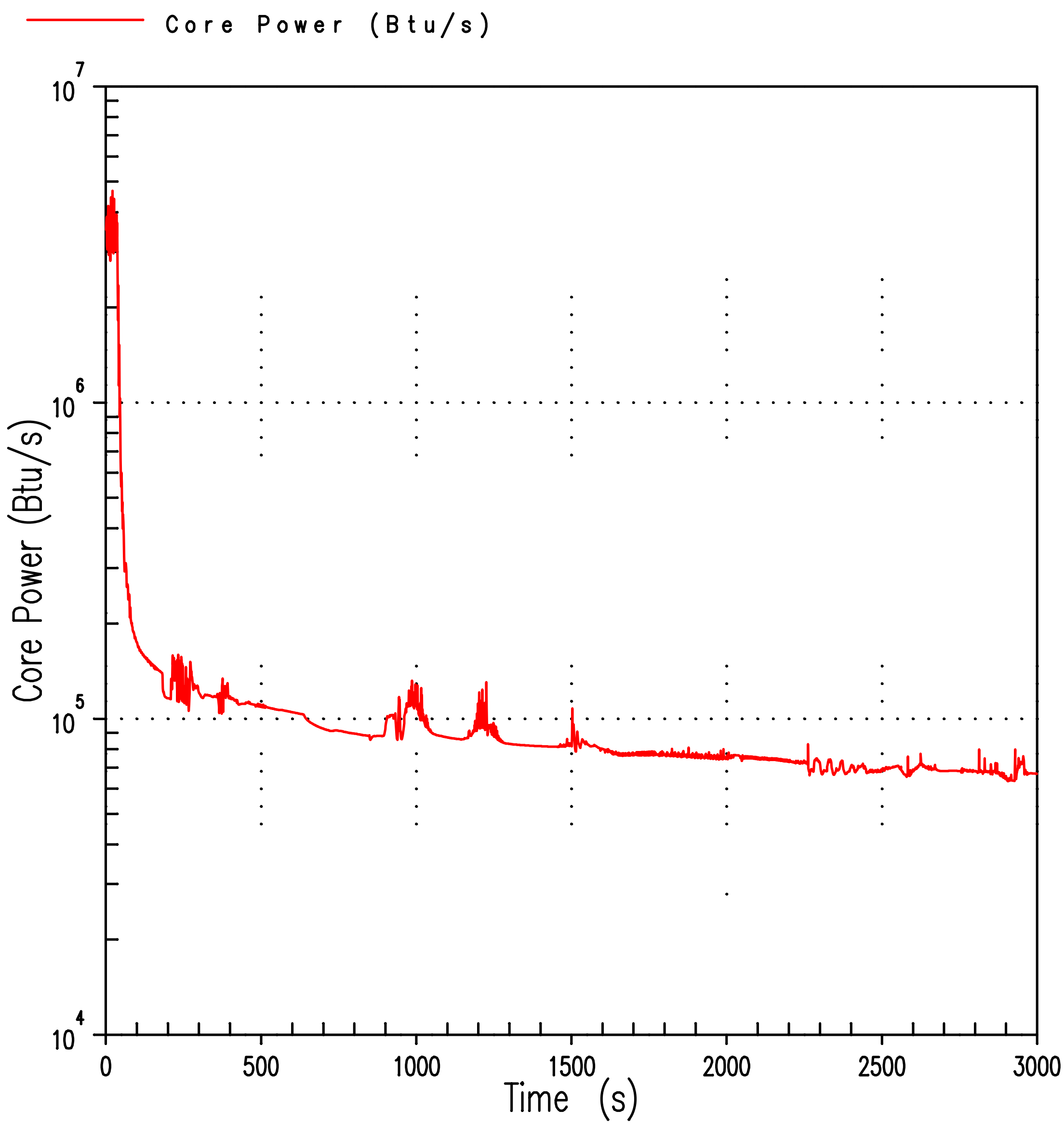


Figure 2.8.5.6.3.2.2-7
Core Inlet Mass Flowrate 4-inch Break

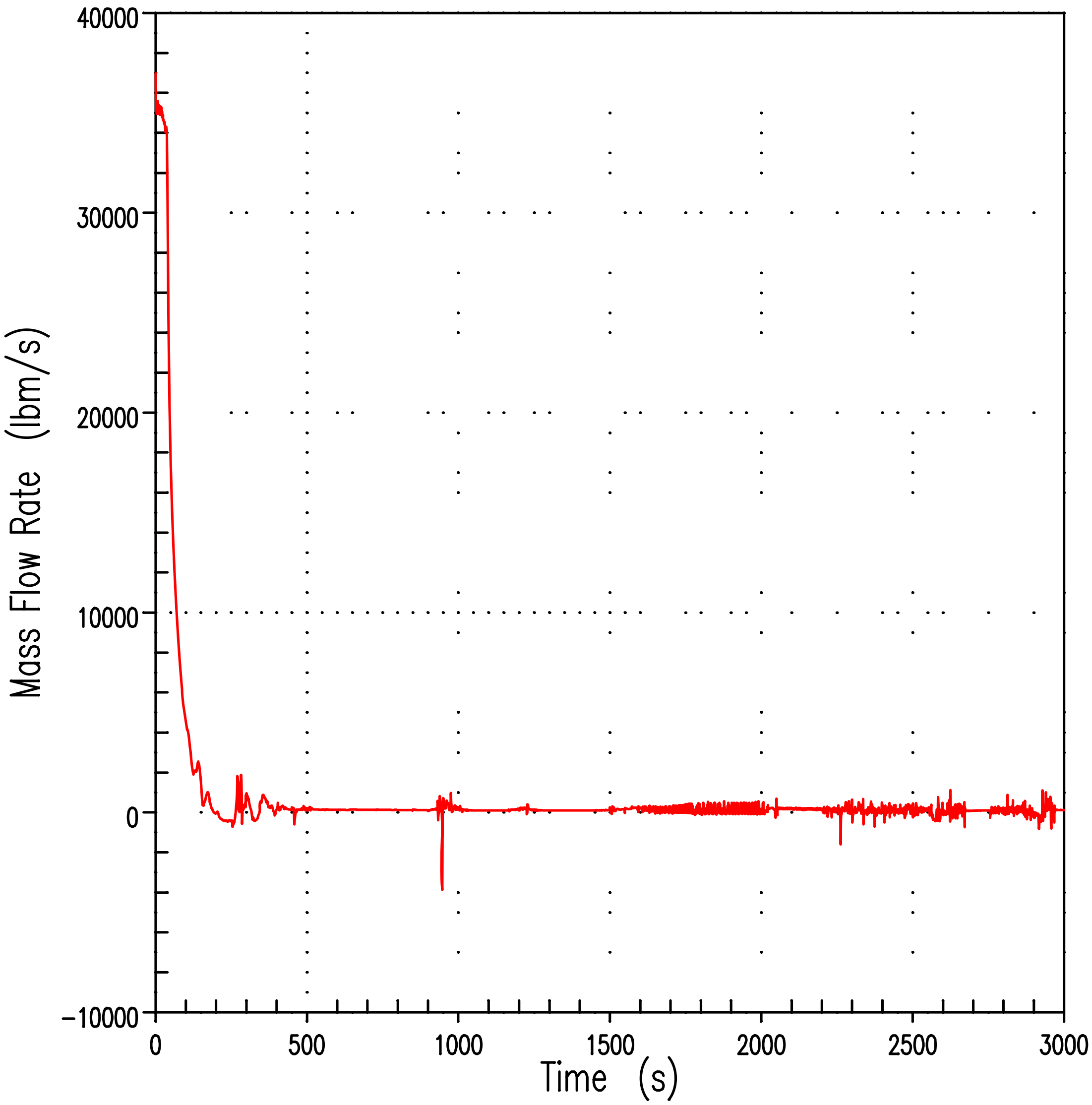


Figure 2.8.5.6.3.2.2-8
Break Mass Flow Rate 4-inch Break

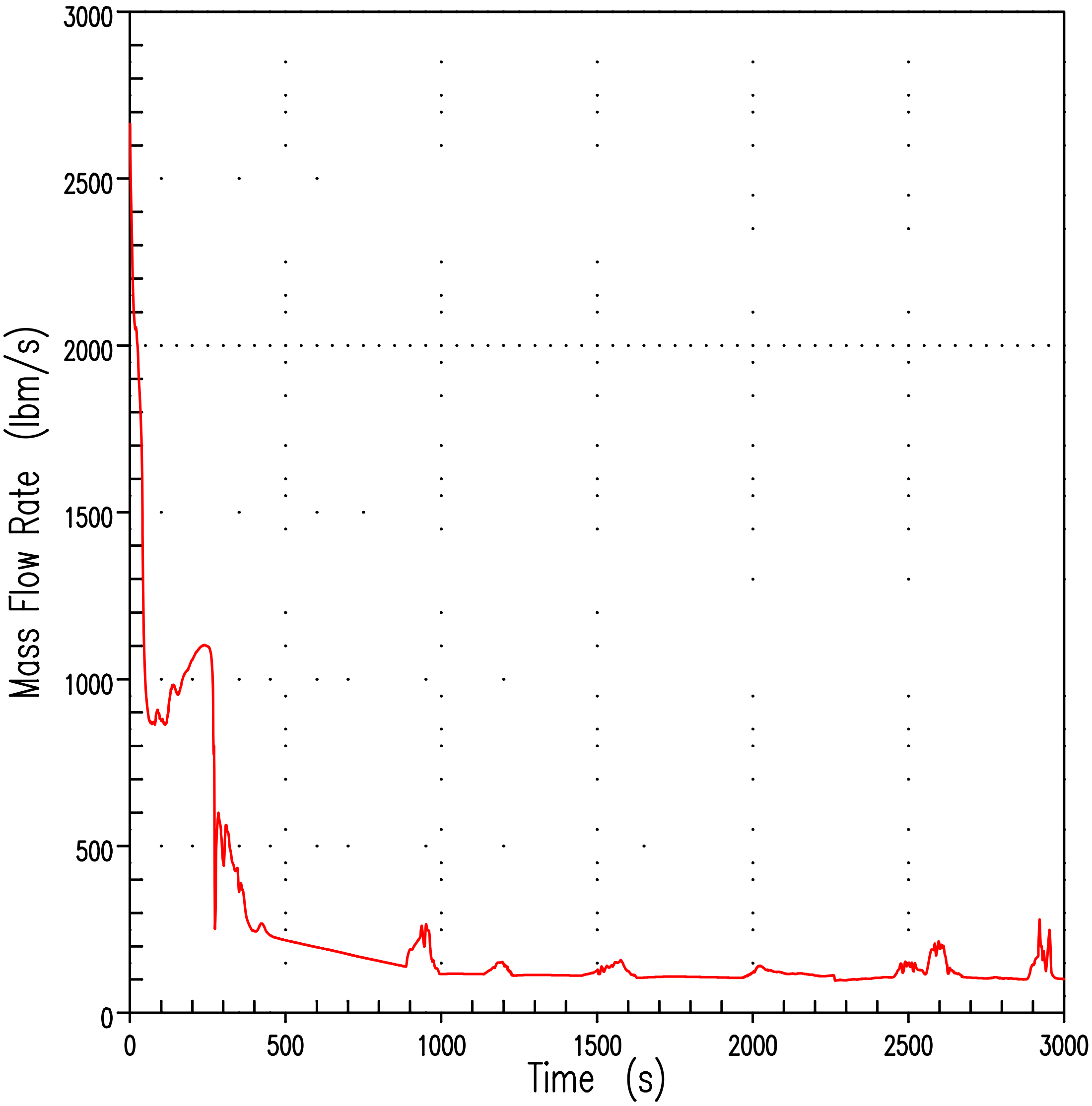


Figure 2.8.5.6.3.2.2-9
Break Quality 4-inch Break

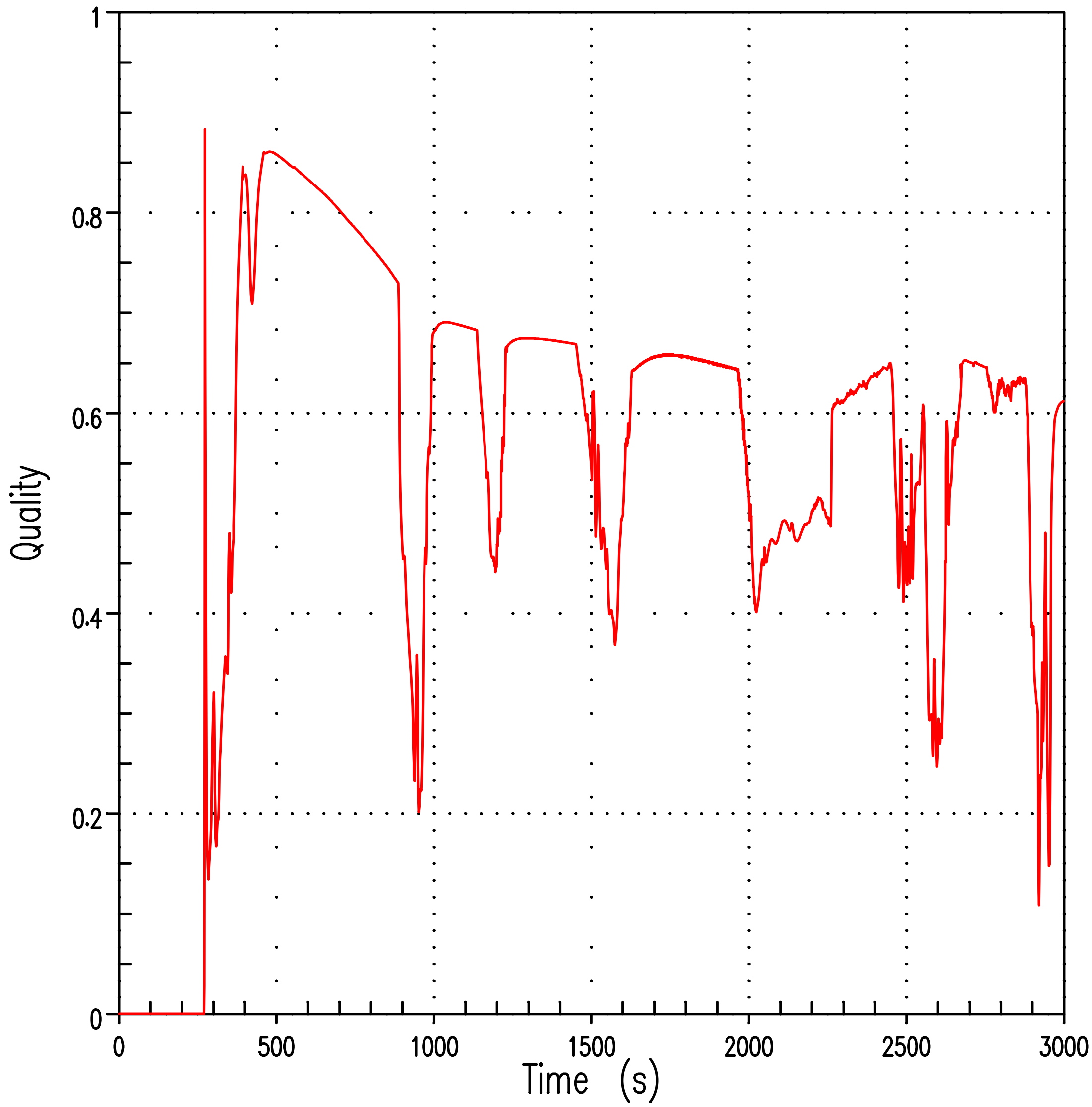


Figure 2.8.5.6.3.2.2-10
Steam Temperature at PCT Elevation 4-inch Break

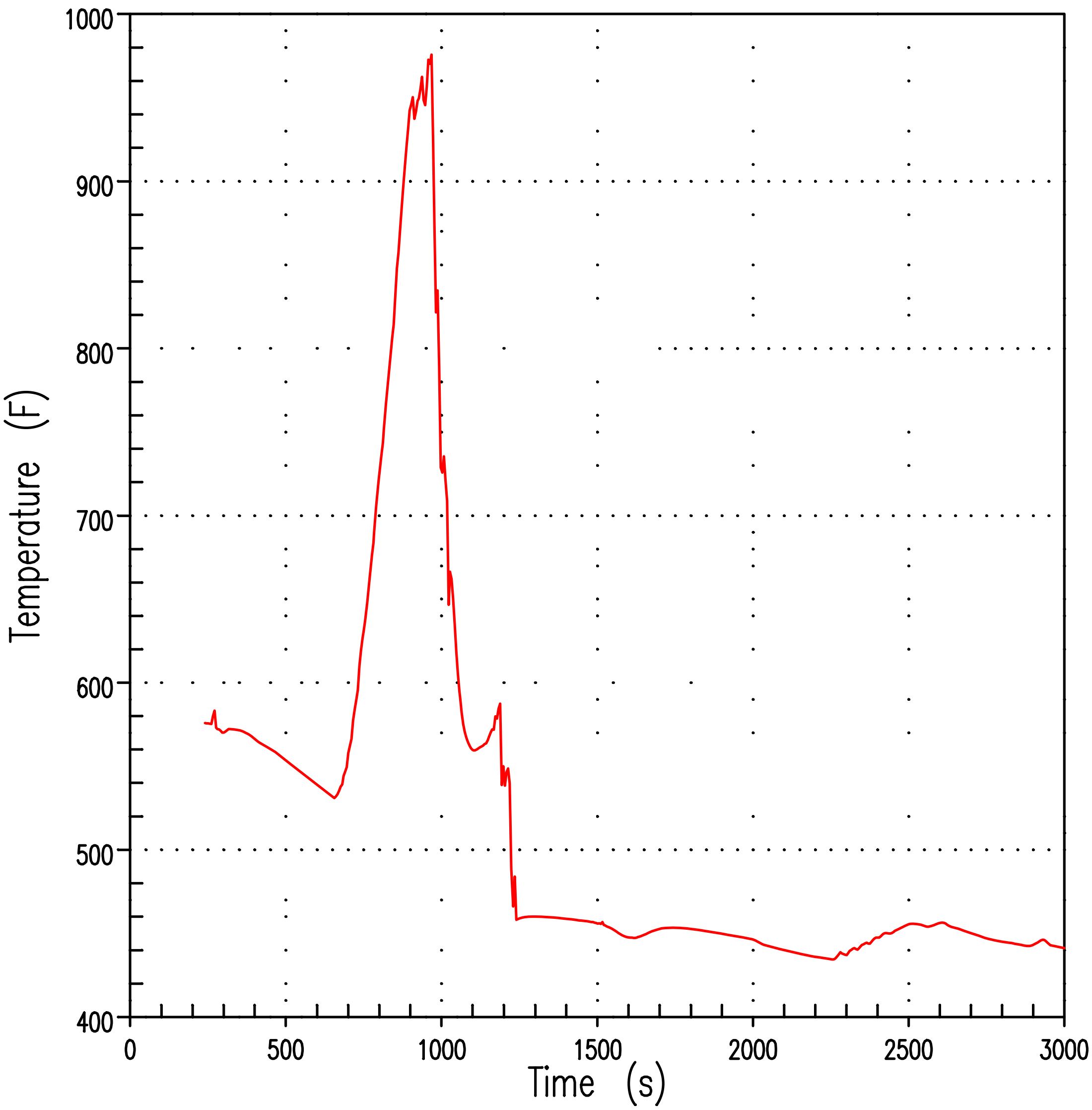


Figure 2.8.5.6.3.2.2-11
Heat Transfer Coefficient at PCT Elevation 4-inch Break

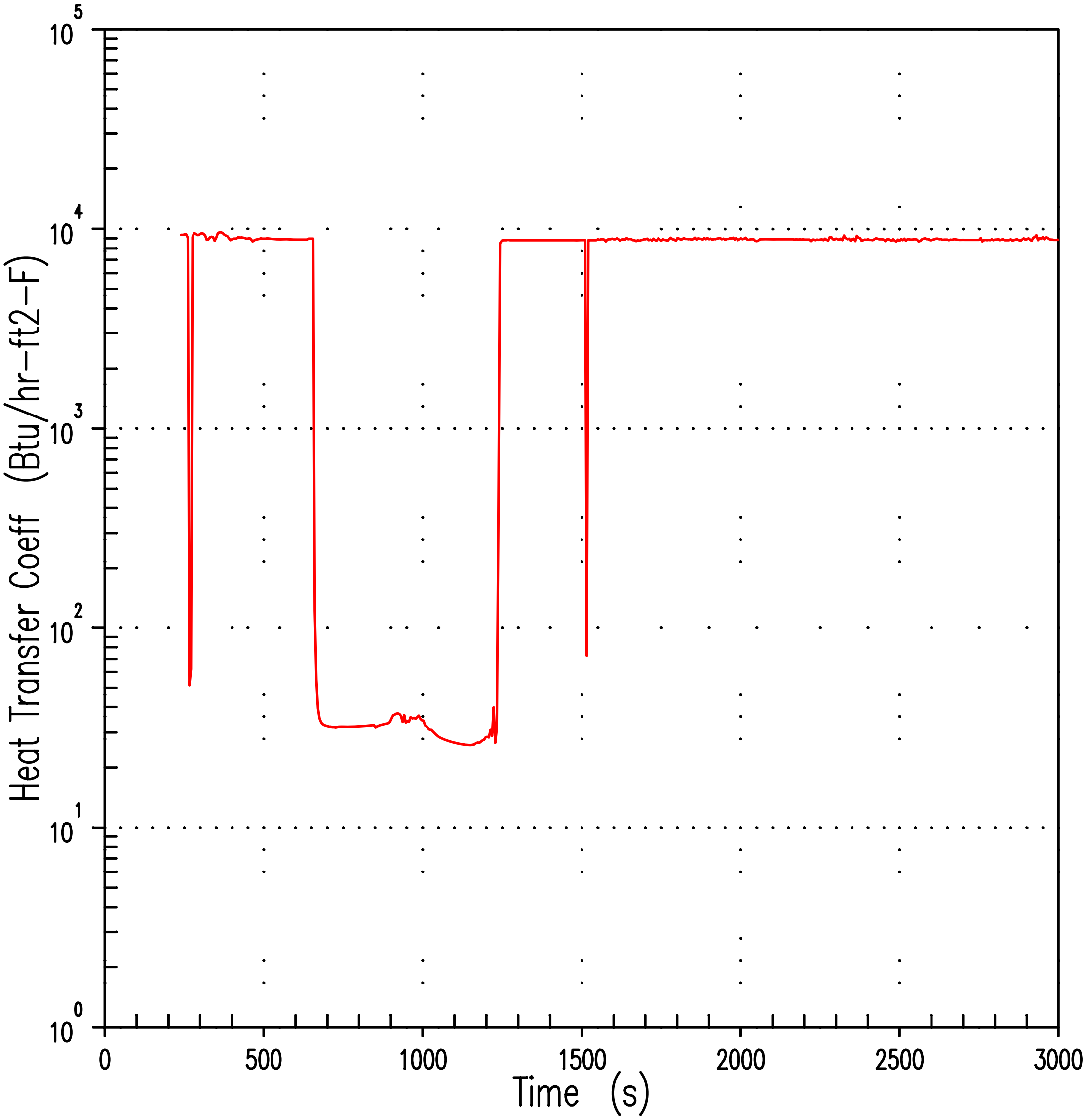


Figure 2.8.5.6.3.2.2-12
Accumulator Injection Flow Rate 4-inch Break

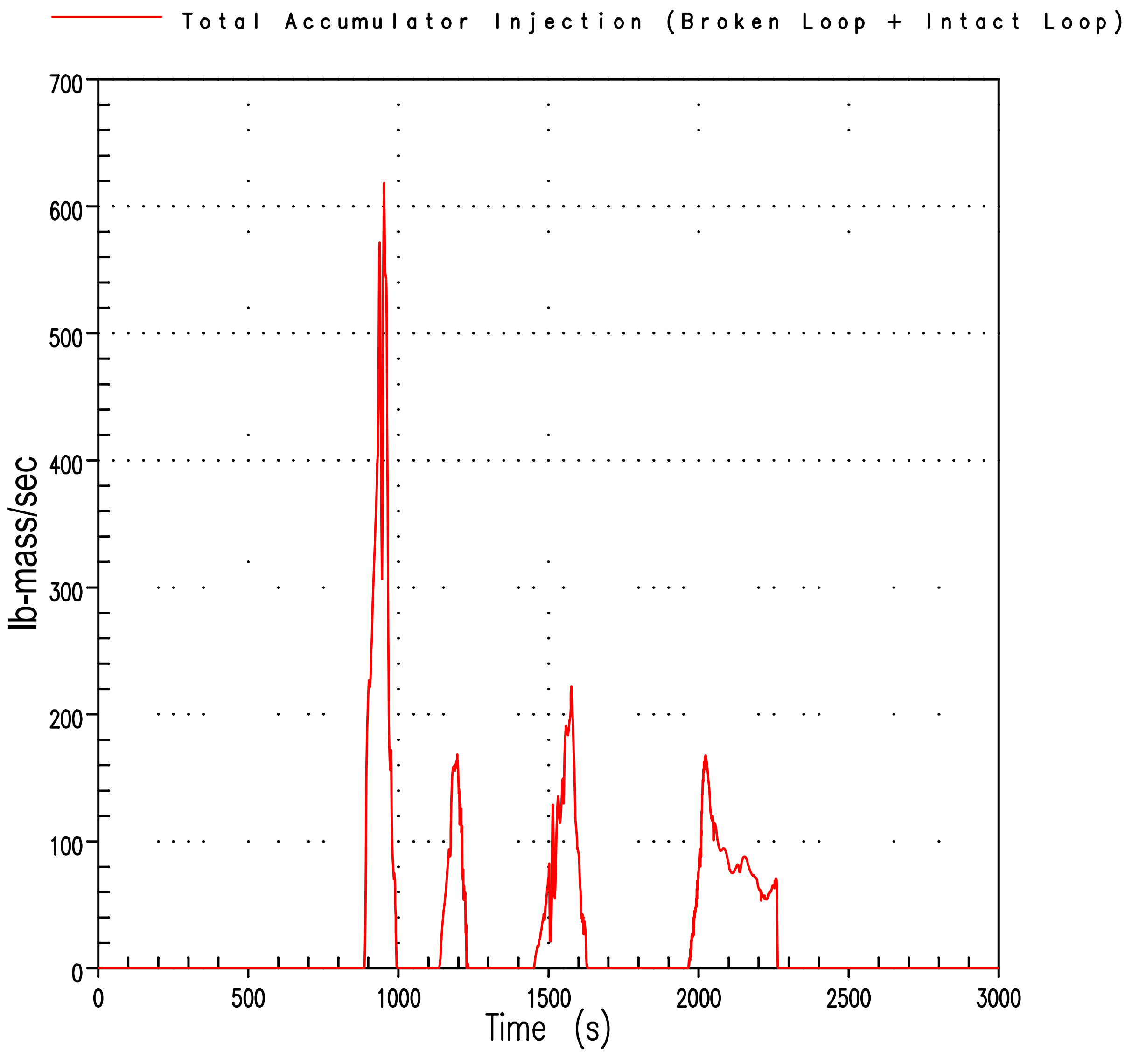


Figure 2.8.5.6.3.2.2-13
Cold Legs Condensation Rates 4-inch Break

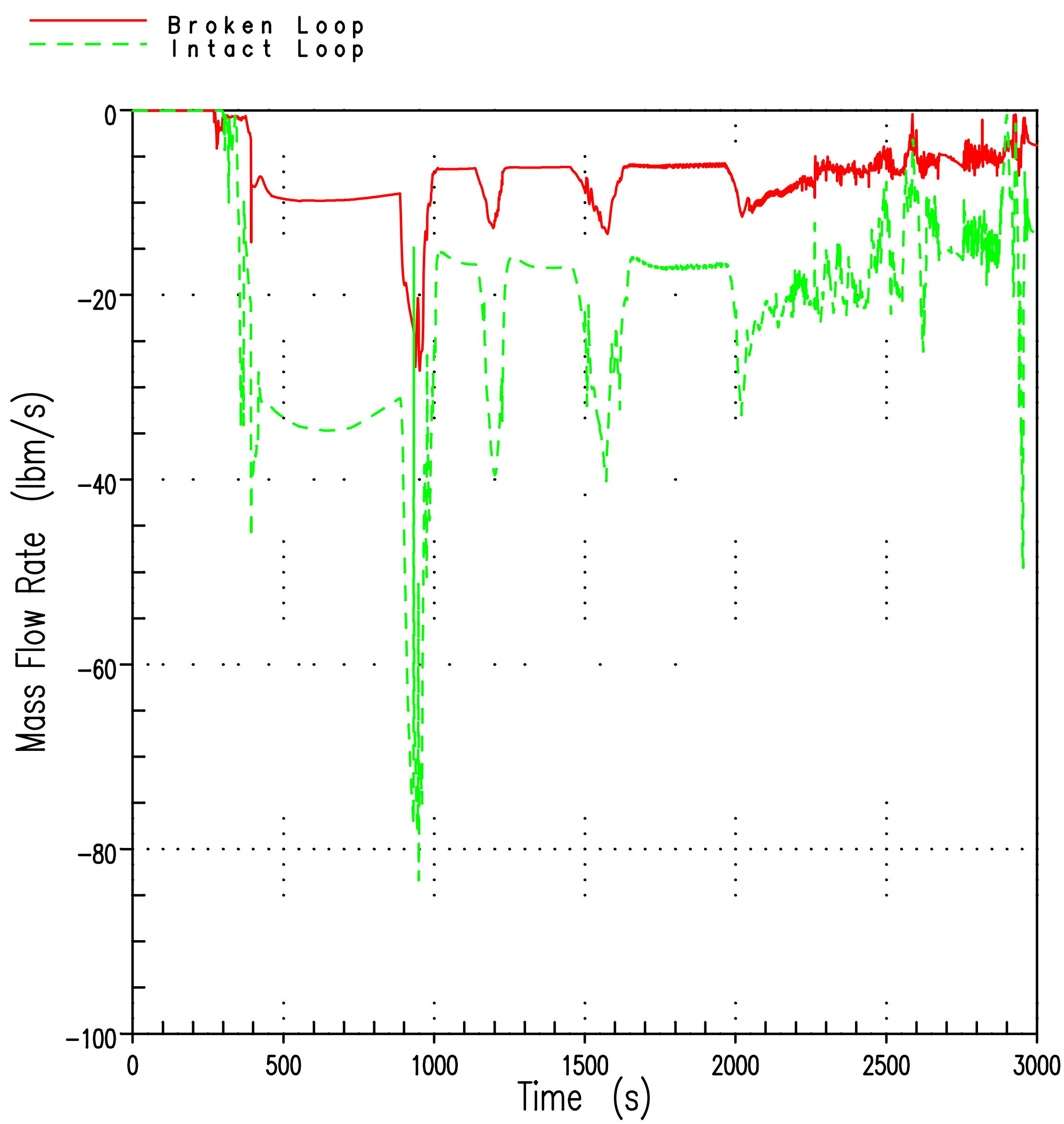
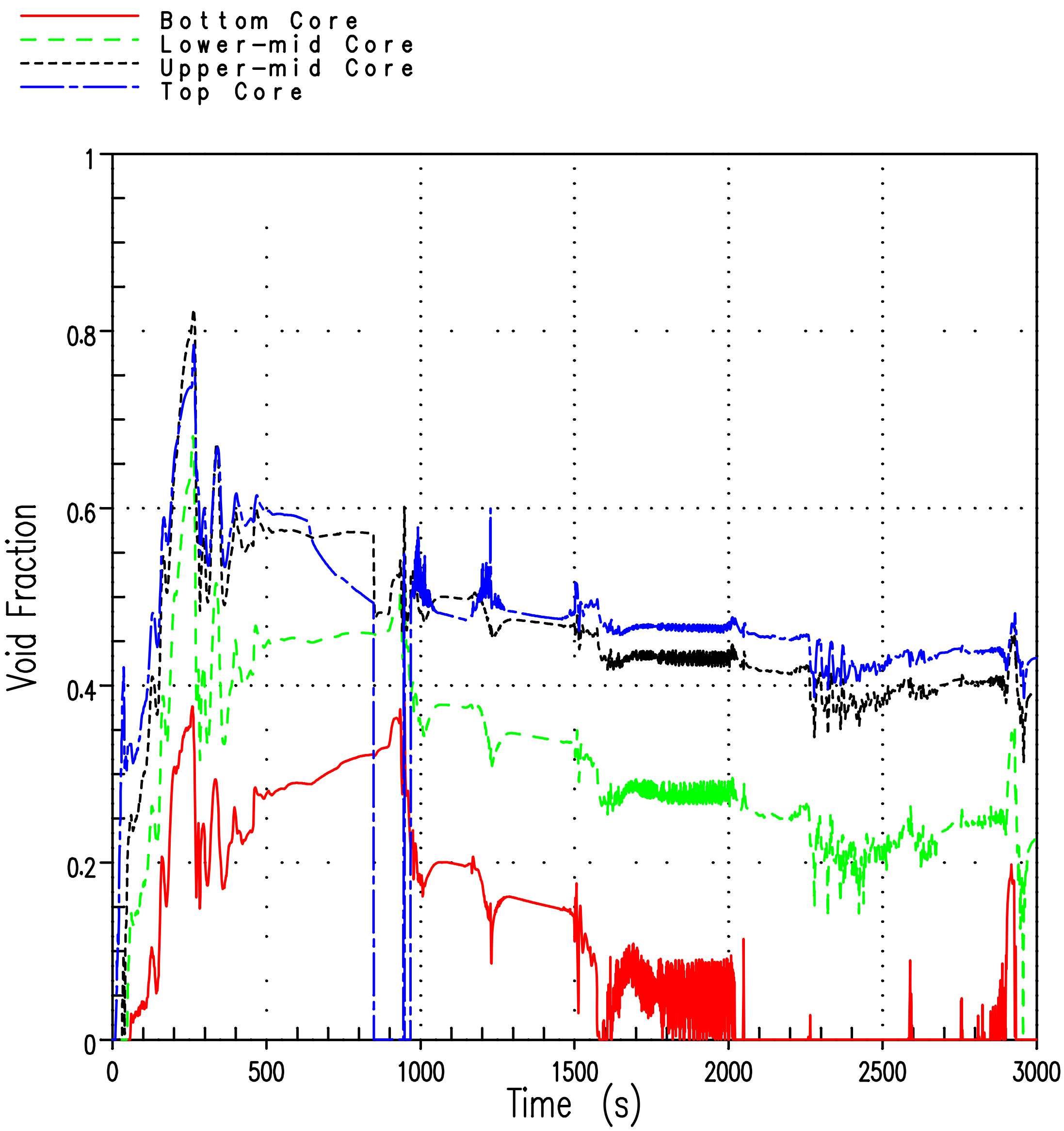


Figure 2.8.5.6.3.2.2-14
Void Fractions in Core Nodes 4-inch Break



2.8.5.6.3.2.3 LOCA Forces

The LOCA hydraulic forces analysis generates the hydraulic forcing functions that act on RCS components as a result of the postulated LOCA. The most recent qualification of the vessel internals and fuel was performed using an advanced beam model version of MULTIFLEX 3.0 (Reference 1), in accordance with methodology approved by the NRC in WCAP-15029-P-A (Reference 2). This same version of the MULTIFLEX code was used in the hydraulic forces analysis for the MPS3 SPU.

2.8.5.6.3.2.3.1 Input Parameters, Assumptions, and Acceptance Criteria

To conservatively calculate LOCA hydraulic forces for MPS3, the following operating conditions were considered in establishing the limiting temperature and pressures:

- Initial RCS conditions associated with a minimum thermal design flow of 90,800 gpm per loop
- Uprated core power of 3650 MWt (analyzed nuclear steam supply system [NSSS] power of 3666 MWt)
- A nominal RCS hot full power (HFP) T_{avg} range of 571.5°F to 589.5°F. This provides an RCS T_{cold} range of 537.4°F to 556.4°F.
- An RCS temperature uncertainty of ±6.0°F
- A feedwater temperature range of 390.0°F to 445.3°F
- A nominal RCS pressure of 2250 psia
- A pressurizer pressure uncertainty of ±50 psi

Based on these conditions, the LOCA hydraulic forces were generated at a minimum T_{cold} of 531.4°F, including uncertainty, and a pressurizer pressure of 2300 psia, including uncertainty.

The LHFF and loads that occur as a result of a postulated LOCA are calculated assuming a limiting break location and break area. The NRC's revision to GDC-4 allowed the main coolant piping breaks to be "excluded from the design basis when analyses reviewed and approved by the commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for piping." This exemption is generally referred to as "leak-before-break." The analysis presented in WCAP-10586 (Reference 3) is technical justification for eliminating primary loop pipe ruptures from the design basis for MPS3. The applicability of a LBB design basis eliminating primary loop piping breaks for MPS3 was approved by the NRC staff (Reference 6). Thus, the primary loop piping breaks did not need to be considered when generating MPS3 LOCA hydraulic forces. The breaks that were considered were the 10-inch accumulator line connection to the cold leg and the 12-inch RHR and 14-inch pressurizer surge line connections on the hot leg.

2.8.5.6.3.2.3.2 Description of Analyses and Evaluations - LOCA Forces

LOCA hydraulic forces were generated with a focus on the component of interest (e.g., loop, vessel, steam generator, or rod control cluster assembly [RCCA] guide tubes) using the advanced beam model version of MULTIFLEX 3.0 (Reference 1), and assuming a conservative break opening time of 1 millisecond.

Generally, this improved modeling results in lower, more realistic, but still conservative hydraulic forces on the core barrel.

The MULTIFLEX computer code calculated the thermal-hydraulic transient within the RCS and considered subcooled, transition, and early two-phase (saturated) blowdown regimes. The code used the method of characteristics to solve the conservation laws, assuming one-dimensional (1-D) flow and a homogeneous liquid-vapor mixture. The RCS was divided into sub-regions in which each subregion was regarded as an equivalent pipe. A complex network of these equivalent pipes was used to represent the entire primary RCS.

For the RPV and specific vessel internal components, the MULTIFLEX code generated the LOCA thermal-hydraulic transient that was input to the LATFORC and FORCE2 post-processing codes (Reference 4). These codes, in turn, were used to calculate the actual forces on the various components.

These forcing functions for horizontal and vertical LOCA hydraulic forces, combined with seismic, thermal, and flow induced vibration loads, were used in the structural analyses to determine the resultant mechanical loads on the vessel and vessel internal components. The vessel forces results are provided for use in the analyses described in Section 2.2.3, Reactor Pressure Vessel Internals and Core Supports.

The loop forces analysis used the THRUST post-processing code to generate X, Y, and Z directional component forces during a LOCA blowdown. RCS pressure, density, and mass flux were calculated by the MULTIFLEX code and were used as inputs to the THRUST code. The THRUST code is described in WCAP-8252 (Reference 5). The loop forces results are provided for use in the analyses described in Section 2.2.2.1, NSSS Piping, Components and Supports; and in Section 2.2.1, Pipe Rupture Locations and Associated Dynamic Effects.

The steam generator forces analysis utilizes the hydraulic transient time-history data, which is extracted directly from the MULTIFLEX computer code output. This analysis is performed to qualify the steam generators for duty using SPU loads. Similarly, hydraulic transient time-history data used in qualification of some of the reactor vessel internal components, such as the baffle bolts or RCCA guide tubes, was also extracted directly from the MULTIFLEX output

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal Application for the impact on the LOCA Forces analysis. As stated in Section 2.8.5.6.3.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for aging management and they remain valid for the SPU conditions.

2.8.5.6.3.2.3.3 Results

All LOCA hydraulic forces analyses for the MPS3 SPU were performed directly at the analyzed NSSS power level of 3666 MWt, using models specific to the MPS3 NSSS design. The analyses of the forces acting on the reactor pressure vessel and vessel internals, fuel, loop piping, steam generator, and RCCA guide tube forces were performed. The results of the LOCA hydraulic forces analyses were then used as input to the calculations for component qualification.

Discussion of Margin Change

As previously mentioned, the LOCA Forces are used as input to the various structural analyses, so margin quantification would be appropriately derived from the calculations for the specific component. Qualitatively speaking, margin in the Forces analyses is realized by analyzing smaller diameter lines, because larger diameter lines would yield higher forces.

2.8.5.6.3.2.3.4 References

1. WCAP-9735, Rev. 2, (Proprietary), and WCAP-9736, Rev. 1, (Nonproprietary), MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic- Structural System Dynamics Advanced Beam Model, K. Takeuchi, et al., February 1998.

2. WCAP-15029-P-A, (Proprietary), and WCAP-15030-NP-A, (Nonproprietary), Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions, R. E. Schwirian, et al., January 1999.

3. WCAP-10586, (Nonproprietary), Technical Basis for Eliminating Large Primary Loop Pipe Rupture as a Structural Design Basis for Millstone Unit 3, E. L. Furchi, et al., June 1984.

4. WCAP-8708-P-A, (Proprietary) and WCAP-8709-A, (Nonproprietary), MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics, K. Takeuchi, et al., September 1977.

5. WCAP-8252, (Nonproprietary), Rev. 1, Documentation of Selected Westinghouse Structural Analysis Computer Codes, K. M. Vashi, May 1977.

6. NRC Letter Dated June 5, 1985, "Request for Exemption from a Portion of General Design Criterion 4 of Appendix A to 10 CFR 50 Regarding the Need to Analyze Large Primary Loop Pipe Ruptures as the Structural Design Basis for Millstone Nuclear Power Station, Unit 3."

2.8.5.6.3.2.4 Post-LOCA Subcriticality

2.8.5.6.3.2.4.1 Introduction

In support of the SPU, post-LOCA subcriticality sump boron calculations were performed. The methodology used to demonstrate MPS3 compliance with the requirements of 10 CFR 50.46 Paragraph (b), Item (5), is documented in WCAP-8339 (Reference 1). Reference 1 states that the core will remain subcritical post-LOCA by borated water from the various injected ECCS water sources. Post-LOCA sump boron calculations demonstrate that the core will remain subcritical upon entering and during the sump recirculation phase of ECCS injection. Containment sump boron concentration calculations are used to develop a core reactivity limit that is confirmed as part of the Westinghouse Reload Safety Evaluation Methodology (Reference 2).

2.8.5.6.3.2.4.2 Input Parameters, Assumptions, and Acceptance Criteria

The input parameters and assumptions used in the sump boron calculations are given in Table 2.8.5.6.3.2.4-1.

The sump boron concentration calculational model is based on the following assumptions:

- The calculation of the sump mixed mean boron concentration assumes minimum mass and minimum boron concentrations for significant boron sources and maximum mass and minimum boron concentration for significant dilution sources.
- Boron is mixed uniformly in the sump. The post-LOCA sump inventory is made up of constituents that are equally likely to return to the containment sump; i.e., selective holdup in containment is neglected.
- The sump mixed mean boron concentration is calculated as a function of the pre-trip RCS conditions.

There are no specific acceptance criteria when calculating the post-LOCA sump boron concentration. However, the resulting sump boron concentration, which is calculated as a function of the pre-LOCA RCS boron concentration, is reviewed for each cycle-specific core design to confirm that adequate boron exists to maintain subcriticality in the long-term post-LOCA.

2.8.5.6.3.2.4.3 Description of Analyses and Evaluations

With respect to post-LOCA criticality, a post-LOCA subcriticality boron limit curve was developed for the SPU plant conditions. The curve is included in the RSAC for each reload cycle. Provided that the cycle-specific maximum critical boron concentration remains below the post-LOCA sump boron concentration limit curve (for all rods out, no Xenon, 68 - 212°F), the core remains subcritical post-LOCA, and decay heat can be removed for the extended period required by the remaining long-lived radioactivity.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the Post-LOCA Subcriticality Analysis. As stated in Section 2.8.5.6.3.1, transient analyses are not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for License Renewal and they remain valid for the SPU conditions.

2.8.5.6.3.2.4.4 Results

A post-LOCA subcriticality boron limit curve was developed for the SPU plant conditions. The SPU Post-LOCA subcriticality boron limit curve is shown in Figure 2.8.5.6.3.2.4-1. Cycle-specific reload safety evaluations will ensure that the core will remain subcritical post-LOCA, thus addressing the GDC-27 requirement that the capability to cool the core is maintained.

2.8.5.6.3.2.4.5 References

1. WCAP-8339, “Westinghouse Emergency Core Cooling System Evaluation Model - Summary,” June 1974.

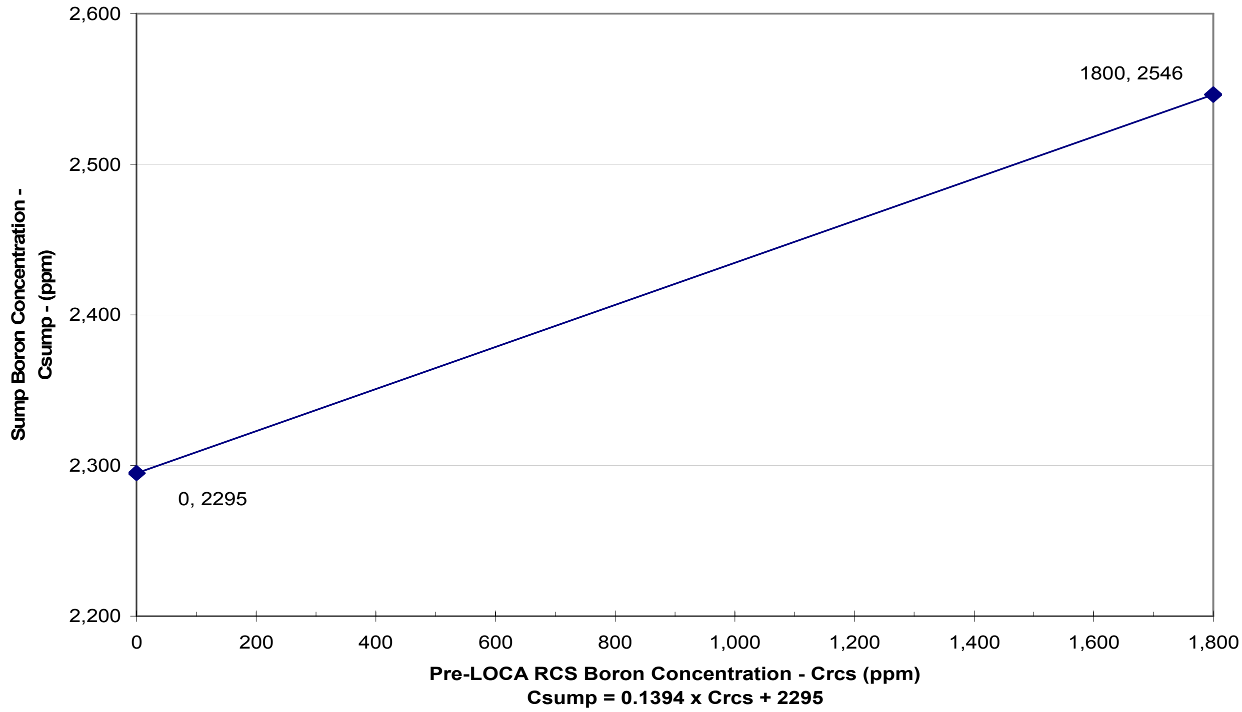
2. WCAP-9272-P-A, “Westinghouse Reload Safety Evaluation Methodology,” July 1985.

Table 2.8.5.6.3.2.4-1
MPS3 Post-LOCA Subcriticality Sump Boron Calculation Input Parameters and Assumptions

Parameter	Current Value	SPU Value
RWST Boron Concentration, Minimum (ppm)	2700	2700
Accumulator Boron Concentration, Minimum (ppm)	2600	1900[1]
RWST Volume, Assumed Minimum (gallons)	605,000	598,000[2]
Total Sump Water Mass, Assumed (lbm)	6,255,616	6,060,576[2]

1. Calculation value of 1900 ppm bounds Tech Spec value of 2600.
2. Assumed RWST minimum volume was reduced to agree with conservative interpretation of FSAR Figure 6.3-6. Total sump water mass is affected accordingly.

Figure 2.8.5.6.3.2.4-1
MPS3 SPU Post-LOCA Subcriticality Boron Limit Curve



2.8.5.6.3.2.5 Post-LOCA Long Term Cooling

In support of the SPU, a post-LOCA long term cooling analysis was performed. There are two aspects to a long term cooling analysis; the potential for boric acid precipitation and maintaining long term decay heat removal. This analysis satisfies the requirements of 10 CFR 50.46 Paragraph (b), Item (4) and 10 CFR 50.46, Paragraph (b), Item (5).

The injection and sump recirculation ECCS modes are described in the FSAR Section 6.3. Boric acid precipitation during long term cooling is addressed in FSAR Section 6.3.2.5. Operator actions to prevent boric acid precipitation are described in the FSAR Section 6.3.2.1 and FSAR Section 15.6.5.3. The switchover from injection mode to cold leg recirculation mode and the switchover from cold leg recirculation mode to hot leg recirculation mode are described in FSAR Section 6.3.2 and Table 6.3-7.

2.8.5.6.3.2.5.1 Input Parameters, Assumptions, and Acceptance Criteria

The major inputs to the boric acid precipitation calculation include core power assumptions and assumptions for boron concentrations and water volume/masses for significant contributors to the containment sump. The input parameters used in the MPS3 SPU boric acid precipitation calculations are given in Table 2.8.5.6.3.2.5-1.

The boric acid precipitation calculation model is based on the following assumptions:

- The boric acid concentration in the core region is computed over time with consideration of the effect of core voiding on liquid mixing volume. Voiding is calculated using the Modified Yeh Correlation described in Reference 1.
- The core mixing volume used in the calculations is shown to be conservative with respect to the potential negative effects of loop pressure drop on core mixing volume.
- The boric acid concentration limit is the experimentally determined boric acid solubility limit as reported in Reference 2 and summarized in Table 2.8.5.6.3.2.5-2 and Figure 2.8.5.6.3.2.5-1. For large breaks and large small breaks, the effect of containment or RCS pressure above atmospheric pressure is not credited and the boric acid solubility limit at 218°F (boiling point of saturated boric acid solution at atmospheric conditions) is assumed. For large small breaks where RCS depressurization is not complete or for even smaller small breaks where the RCS might be at elevated pressures at hot leg switchover time, the solubility limit associated with the saturation temperature of water at the associated elevated pressure is credited.
- The liquid mixing volume used in the calculation includes 50 percent of the lower plenum volume.
- For SBLOCA scenarios, the analysis does not assume a specific start time for cooldown/depressurization emergency procedures, nor does it assume depressurization to some minimum pressure at hot leg switchover time. Nevertheless, for the purpose of defining expected scenarios, it is anticipated that operators begin cooldown/depressurization within one hour of the initiation of the event.

- The effect of the containment sump pH additive TSP on increasing the boric acid solubility limit is not credited.
- The boric acid concentration of the make-up containment sump water during recirculation is a calculated sump mixed mean boron concentration. The calculation of the sump mixed mean boron concentration assumes maximum mass and maximum boron concentrations for significant boron sources, and minimum mass and maximum boron concentrations for significant dilution sources.
- ECCS flow and enthalpy changes that may occur during the switchover from injection mode to sump recirculation are not part of the long term cooling analysis scope and were instead considered in the Small Break LOCA Analysis.

In addition to the above assumptions NRC requirements pertaining to the decay heat generation rate for both boric acid accumulation and decay heat removal which is based on the 1971 ANS Standard for an infinite operating time with 20 percent uncertainty is utilized as an input to prepare the boric acid precipitation calculation. The assumed core power includes a multiplier to address instrument uncertainty as identified by Section 1.A of 10 CFR 50, Appendix K.

The above methodology meets NRC guidance as presented in Reference 3 and is consistent with the interim methodology reported in Reference 4.

The acceptance criteria for the Long Term Cooling Analysis are demonstrated by the ability to keep the core cool after a LOCA and calculating a HLSO time with methods, plant design assumptions, and operating parameters as specified by the utility and consistent with the interim methodology reported in Reference 4. The FSAR, Tech Specifications, and EOPs have been revised to support the maximum time to establish simultaneous hot leg and cold leg injection.

ECCS recirculation flows are evaluated by comparing minimum safety injection pump flows to the flows necessary to dilute the core and replace core boiloff, thus keeping the core quenched.

2.8.5.6.3.2.5.2 Description of Analyses and Evaluations

There are two aspects to a long term cooling analysis; the potential for boric acid precipitation to occur and decay heat removal. The purpose of the boric acid precipitation analysis is to demonstrate that the maximum boric acid concentration in the core remains below the solubility limit, thereby preventing the precipitation of boric acid in the core. If boric acid were to precipitate in the core region, the precipitate might prevent water from remaining in contact with the fuel cladding and, consequently, result in the core temperature not being maintained at an acceptably low value. The boric acid precipitation analysis determines the appropriate time for switching some or all ECCS recirculation flow to the hot leg and verifies that there is sufficient dilution flow through the core to dilute the core and prevent boric acid buildup.

Prior to sump recirculation, core cooling is addressed by the Large Break LOCA analysis that demonstrates core reflood and stable and sustained quench, and by the SBLOCA analysis that demonstrates core recovery. After a SBLOCA, RCS system refill, depressurization and entry into shutdown cooling, or depressurization and indefinite sump recirculation occurs. With the switch to sump recirculation, long term cooling is addressed by demonstrating that the core remains covered with two-phase mixture in the long term, thereby ensuring that the core temperature is maintained at an acceptably low value. Paragraph (b)(5) of 10 CFR 50.46 is satisfied when the fuel in the core is quenched, the switch from injection to recirculation phases is complete, and the recirculation flow is large enough to match the boiloff rate. Prior to hot leg recirculation, the ECCS recirculation flow must be sufficient to remove decay heat. ECCS pump availability and specific flow path alignments may reduce ECCS recirculation flow as compared to the flows available during the injection phase. After the switch to hot leg recirculation, core flow sufficient to dilute the core or prevent boric acid buildup, by definition, exceeds core boiloff and therefore provides core cooling.

The Long Term Cooling Analysis described here supports the Post-LOCA Boric Acid Precipitation Control Plan presented in Table 2.8.5.6.3.2.5-3 The flowchart in Figure 2.8.5.6.3.2.5-2 shows the applicability of the calculations to the specific post-LOCA scenarios.

Large Break LOCAs

Large breaks (double-ended guillotine down to approximately 1.0 ft^2) rapidly depressurize to very near containment pressure with no operator action. The 14.7 psia boric acid precipitation calculation models this scenario and calculates the boric acid build-up for the limiting condition of a cold leg break. Dilution and core cooling flows are confirmed for 14.7 psia RCS backpressure. After hot leg switchover, the hot leg injected flow provides immediate core dilution for a cold leg break. If the break is in the hot leg, injected ECCS flow to the cold leg is sufficient to prevent the buildup of boric acid in the core after switchover to hot leg recirculation. Therefore, after hot leg switchover, simultaneous hot leg and cold leg injection prevents boric acid precipitation in the long term.

Large breaks that lead to rapid RWST draindown represent the limiting case for recirculation flow requirements. At the start of sump recirculation, ECCS flows are evaluated.

Large Small Break LOCAs

Large small breaks (approximately 0.1–1.0 ft^2) depressurize to relatively low pressures (before the potential for boric acid precipitation) with no operator action. The 120 psia boric acid precipitation calculation models this scenario and calculates the boric acid build-up for the limiting condition of a cold leg break. The 120 psia calculations consider less core voiding, a lower h_{fg} (heat of vaporization), and do not credit SI subcooling to reduce core boiloff. After hot leg switchover, as with large breaks, the hot leg injected flow provides core dilution for cold leg breaks and cold leg injected flow prevents buildup of boric acid in the core for hot leg breaks. Dilution and decay heat removal flows are confirmed as adequate at 120 psia RCS backpressure. Core dilution flow provides effective core cooling.

Small Break LOCA

For small breaks (approximately 0.005–0.1 ft^2), emergency procedures instruct operators to take action to depressurize and cool down the RCS. Although this depressurization and cooldown process typically begins within one hour after the event, the long term cooling analysis makes no specific assumptions regarding time to depressurize. Depressurization to 120 psia (the threshold for boric acid precipitation concerns) may occur before or after hot leg switchover time. In either case, the boric acid buildup at hot leg switchover time is conservatively represented by that calculated for the 120 psia RCS backpressure scenario since this calculation takes no credit for SI subcooling, nor any beneficial effects of the operator action (such as reduced net core boil-off due to condensation in the steam generators). If 120 psia is reached before hot leg switchover time, the core dilution flow after hot leg switchover, which is confirmed as adequate for 120 psia backpressure, provides effective core dilution. If at hot leg switchover time, the 120 psia has not been reached, boric acid precipitation does not occur so long as the RCS remains above this pressure since water and boric acid are miscible at the saturation temperature for these pressures. Even if the RCS pressure is above 120 psia at 12 hours after the LOCA with no core dilution flow, the total boric acid in the core is well below the saturation capacity at the corresponding saturation temperature. Furthermore, if after 12 hours with no dilution flow, the RCS is at saturation and depressurized at the maximum cooldown rate, the core is diluted prior to reaching the boric acid precipitation point. If subcooled core conditions are reached either before or after hot leg switchover, boric acid precipitation is not a concern since there is no net boiling in the core. If subcooled core entry conditions are not reached, the operators continue to depressurize the RCS under controlled conditions. Sump recirculation continues, decay heat in the core decreases, and core dilution flow prevents the buildup of boric acid. Eventually, subcooled core conditions are reached, the system is put into RHR or it remains in indefinite recirculation cooling.

Very Small Break LOCA

For very small breaks (less than approximately 0.005 ft^2), emergency procedures instruct operators to take action to depressurize the RCS. Because the break is small, subcooled conditions are reached prior to depressurization to 120 psia (the threshold for boric acid precipitation concerns). Natural circulation, if lost, is quickly restored. While in natural circulation, boric acid precipitation is not a concern because the core region is not stagnant. When subcooled conditions occur, net core boiling ceases and boric acid does not accumulate. Eventually, subcooled core conditions will be reached, the system will be put into RHR or continued natural circulation and sump recirculation will keep the boric acid from accumulating in the core. It is important to note that MPS3 is designed so that high pressure SI provides hot leg recirculation flow. As such it is not necessary to depressurize the RCS to get effective dilution flow.

Impact on Renewed Plant Operating License Evaluations and License Renewal

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal SER for the impact on the Post-LOCA Long Term Cooling Analysis. As stated in Section 2.8.5.6.3.1, the Post-LOCA Long Term Cooling Analysis is not within the scope of license renewal. Therefore, there is no impact on the evaluations performed for License Renewal and they remain valid for the SPU conditions.

2.8.5.6.3.2.5.3 Results

To address large break LOCAs, MPS3 SPU Post LOCA boric acid buildup calculations for 14.7 psia resulted in a 3 to 5 hour timeframe to establish simultaneous hot leg and cold leg SI injection. Figure 2.8.5.6.3.2.5-3 shows the buildup of boric acid versus time and the boric acid solubility limit used for this scenario. Although the boric acid buildup calculations for this scenario apply to RCS pressures of up to 30 psia, the boric acid solubility above the atmospheric boiling point of a saturated boric acid and water solution is not credited. Figure 2.8.5.6.3.2.5-3 also shows the dilution effect of the hot leg injected flow after simultaneous hot leg and cold leg is established.

To address small break LOCAs, MPS3 SPU Post LOCA boric acid precipitation calculations for 120 psia were performed. These calculations show that there is considerable margin to the boric acid solubility limit at the designated switchover time for this scenario. The 120 psia calculations consider less core voiding, a lower heat of vaporization (h_{fg}), and do not credit SI subcooling to reduce core boil-off. Since the boric acid buildup calculations for this scenario apply to RCS pressures of 30 to 120 psia, the boric acid solubility for the saturation temperature of water at 30 psia was credited. Figure 2.8.5.6.3.2.5-4 shows the buildup of boric acid versus time and the solubility limit appropriate for this scenario. Figure 2.8.5.6.3.2.5-4 also shows the dilution effect of the hot leg injected flow after simultaneous hot leg and cold leg is established.

In the unlikely event that the RCS pressure remains above 120 psia at hot leg switchover time while at saturated conditions, boric acid precipitation does not occur since the total boric acid in the core is well below the saturation capacity at the elevated pressure saturation temperature. In order to demonstrate the effectiveness of hot leg dilution flow for this scenario, calculations were performed for a hypothetical condition where there would be no hot leg dilution flow for 12 hours. Figure 2.8.5.6.3.2.5-5 shows the boric acid concentration in the core with the RCS at 120 psia for 12 hours assuming no SG heat removal, no dilution flow, and no benefit of reduced steaming due to SI subcooling. At 12 hours, the boric acid concentration is still below the boric acid solubility limit at the saturation temperature at 120 psia. Figure 2.8.5.6.3.2.5-5 also shows that if hot leg flow is established at 12 hours and the RCS is at saturation and is then cooled (with corresponding depressurization) at a cooldown rate of 100°F/hr, boric acid precipitation does not occur. The resulting hot leg dilution flow maintains the boric acid concentration in the core well below the solubility limit, even as the solubility limit is reduced due to the RCS cooldown. For MPS3, hot leg dilution flow is provided by the SI pumps which would, in fact provide dilution flow at RCS pressures well above 120 psia.

Calculations were performed to support an early switchover to hot leg or simultaneous injection. Two aspects of early switchover were considered: the hot leg entrainment threshold and core cooling. If switchover occurs too early, injected SI in the hot legs might be carried around the loops and might not be available for core cooling and dilution. Entrainment threshold calculations similar to those reported in Reference 5 demonstrated that significant hot leg entrainment would not occur after 80 minutes. Calculations showed that either hot leg or cold leg flows are sufficient to provide core cooling flow at 3 hours after the LOCA.

Assessments were made of the effect of loop pressure drop and downcomer boiling on the core mixing volume by performing calculations similar to those reported to the NRC in Reference 5 and Reference 6. For MPS3, the total loop pressure drop with and without locked RCP rotor is approximately 1.5E-08 and 7.2E-08, respectively. In all cases, the core region mixing volume assumed in the boric acid buildup calculation was found to be conservatively small in relation to the collapsed liquid volume that would be based on loop pressure drop and available downcomer head.

The effect of the refilling of the pump suction leg loop seals (due to a break at the top of the cold leg pipe) was also assessed by performing calculations similar to those reported to the NRC in

References 5 and 6. For MPS3, the bottom elevation of the loop seal pipes is approximately 15.74 ft relative to the inside bottom of the reactor vessel. The top elevation of the active core is 22.08 ft relative to the inside bottom of the reactor vessel. Consequently, the bottom elevation of the loop seal piping is approximately 6.34 feet below the top of the active fuel. While the simultaneous complete closure of all four loop seals would depress the core mixture to slightly below that associated with the core mixing volume, the expected duration of the depression would be brief. Brief core mixture level depressions would have the benefit of promoting mixing between the core region and lower plenum by cycling liquid back and forth between the core region, lower plenum and downcomer.

An assessment was made of the effect of boric acid plate-out in the SGs by performing calculations similar to those reported to the NRC in Reference 6. These calculations show that, with 10 percent entrainment for 1.5 hours, the total boric acid mass entrained would deposit a coating of approximately 0.002 inches over 10 feet of SG tubes. This coating would not significantly increase loop resistance or depress the core mixture level.

An assessment was made concerning the potential for boric acid precipitation at the hot leg injection point or at colder regions of the vessel. A simplified demonstration calculation showed that the mixing of injected SI with the highly borated solution in the reactor vessel would not initiate boric acid precipitation at the injection point. This calculation ignored temperature and boric acid gradients and assumed effective mixing with no differentiation between different mixing mechanisms such as diffusion (thermal or molecular) and density-driven convection within the vessel. The assessment also concluded that the heating of the injected water as it travels to the core region (either from the downcomer or hot leg) and the expected density-driven mixing mechanisms in the vessel would make it unlikely that significant temperature or boric acid gradients would exist. These conclusions were consistent with those reported to the NRC in Reference 6.

In summary, the MPS3 SPU Post LOCA boric acid precipitation calculations used conservative methodology to establish a 3- to 5-hour timeframe to realign the ECCS to provide SI flow to the hot legs. SI flow to the hot leg provides effective core dilution thus precluding boric acid precipitation in the core. This realignment addresses the requirements of 10 CFR 50.46 (b) (4) coolable geometry and 10 CFR 50.46 (b) (5) long term cooling. ECCS flows during sump recirculation were shown to be sufficient to remove decay heat after a LOCA for SPU plant conditions, provided the ECCS realignment to provide SI flow to the hot legs occurs no sooner than 3 hours following the event. This addresses the requirements of 10 CFR 50.46 (b) (5) long term cooling. Since the Long Term Core Cooling Analyses for the SPU show that no changes to the MPS3 ECCS system are required, GDC-35 requirements continue to be met.

2.8.5.6.3.2.5.4 References

1. H. C. Yeh, “Modification of Void Fraction Calculation,” Proceedings of the Fourth International Topical Meeting on Nuclear Thermal-Hydraulics, Operations and Safety, Volume 1, Taipei, Taiwan, June 6, 1988.

2. P. Cohen, 1980 (Originally published in 1969), Water Coolant Technology of Power Reactors, Chapter 6, “Chemical Shim Control and pH Effect,” ANS-USEC Monograph.

3. Letter dated August 1, 2005 from R. A. Gramm, U. S. Nuclear Regulatory Commission to J. A. Gresham, Westinghouse Electric Company, “Suspension of NRC Approval for Use of Westinghouse Topical Report CENPD-254-P, ‘Post LOCA Long Term Cooling Model’ Due to Discovery of Non-conservative Modeling Assumptions During Calculations Audit”.

4. Letter dated October 3, 2006 from Sean E. Peters, Project Manager, Special Projects Branch, Division of Policy and Rulemaking, Office of Nuclear Reactor Regulation, NRC to Stacey L. Rosenberg, Chief, Special Projects Branch, Division of Policy and Rulemaking, Office of Nuclear Reactor Regulation, NRC, “Summary Of August 23, 2006 Meeting With The Pressurized Water Reactor Owners Group (PWROG) To Discuss The Status Of Program To Establish Consistent Criteria For Post Loss-Of-Coolant (LOCA) Calculations.”

5. Letter L-05-112, FirstEnergy Nuclear Operating Company to USNRC, “Responses to a Request for Additional Information in Support of License Amendment Request Nos. 302 and 173", July 08, 2005.

6. Letter L-05-169, FirstEnergy Nuclear Operating Company to USNRC, “Responses to a Request for Additional Information (RAI dated September 30, 2005) in Support of License Amendment Request Nos. 302 and 173", November 21, 2005.

2.8.5.6.3.3 Conclusion

DNC has reviewed the analyses of the LOCA events and the ECCS. DNC concludes that the analyses have adequately accounted for plant operation at the proposed power level and that the analyses were performed using acceptable analytical models. DNC further concludes that the evaluation has demonstrated that the reactor protection system and the ECCS will continue to ensure that the peak cladding temperature, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling will remain within acceptable limits. Based on this, DNC concludes that the plant will continue to meet the plant's current licensing basis requirements with respect to GDC-4, GDC-27, GDC-35, and 10 CFR 50.46 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the LOCA.

Table 2.8.5.6.3.2.5-1
MPS3 Post-LOCA Long Term Cooling Analysis Input Parameters

Parameter	SPU Value
Analyzed Core Power (MWt)	3650
Analyzed Core Power Uncertainty (percent)	2.0
Decay Heat Standard	1971 ANS, Infinite Operation, plus 20% (10 CFR 50, Appendix K)
H_3BO_3 Solubility Limit (weight percent)	See Table 2.8.5.6.3.2.5-2
RWST Boron Concentration, Maximum (ppm)	2900
RWST Volume, Maximum (gallons)	1,207,000
RWST Temperature, Minimum (°F)	40
Accumulator Boron Concentration, Maximum (ppm)	2900
Accumulator Tank Volume, Maximum (gallons)	7030 per tank
Accumulator Tank Temperature, Minimum (°F)	80
Approximate Total Sump Liquid Mass (lbm)	10,671,000

Table 2.8.5.6.3.2.5-2
Boric Acid Solution Solubility Limit

Temperature, °C (°F)	Solubility g H_3BO_3/100 g of Solution in H_2O	Temperature, °C (°F)	Solubility g H_3BO_3/100 g of Solution in H_2O
P = 1 Atmosphere		75 (167)	17.41
0 (32)	2.70	80 (176)	19.06
5 (41)	3.14	85 (185)	21.01
10 (50)	3.51	90 (194)	23.27
15 (59)	4.17	95 (203)	25.22
20 (68)	4.65	100 (212)	27.53
25 (77)	5.43	103.3 (217.9)	29.27
30 (86)	6.34	**P = P_{SAT}**	
35 (95)	7.19	107.8 (226.0)	31.47
40 (104)	8.17	117.1 (242.8)	36.69
45 (113)	9.32	126.7 (260.1)	42.34
50 (122)	10.23	136.3 (277.3)	48.81
55 (131)	11.54	143.3 (289.9)	54.79
60 (140)	12.97	151.5 (304.7)	62.22
65 (149)	14.42	159.4 (318.9)	70.67
70 (158)	15.75	**171 (339.8) = Congruent Melting of H_3BO_3**	

Table 2.8.5.6.3.2.5-3 Post-LOCA Boric Acid Precipitation Control Plan

Approximate Break Size (ft^2)	Scenario	Analysis
DEG		
	Large Breaks Large breaks will rapidly depressurize to very near containment pressure.	Represented by 14.7 psia boric acid buildup calculation. Dilution flows confirmed for 14.7 psia RCS backpressure.
1.0		
	Large Small Breaks Large small breaks will depressurize to below 120 psia without operator action.	Represented by 120 psia boric acid buildup calculation. Dilution flows are confirmed at 120 psia RCS backpressure.
0.1		
	Small Breaks Emergency procedures will instruct operators to take action to depressurize RCS. Eventually the system will be put into RHR or it will remain in indefinite recirculation cooling.	Credit operator action to depressurize the RCS. If the 120 psia is reached before HLSO time, the 120 psia boric acid buildup calculation applies. If 120 psia is not reached before HLSO time, credit higher boric acid solubility limit. If core subcooling conditions are reached, boric acid precipitation is not a concern since there will be no net boiling in the core.
0.005		
	Very Small Breaks Emergency procedures will instruct operators to take action to depressurize RCS. Subcooled conditions will be reached prior to depressurization to 120 psia (the threshold for boric acid precipitation concerns). Eventually, the system will be put in RHR or it will remain in indefinite recirculation cooling.	Natural circulation, if lost, will be quickly restored. While in natural circulation, boric acid precipitation is not a concern because the core region will not be stagnant.
0.001		
	Leaks Charging System has make-up capacity.	
0.0		

Figure 2.8.5.6.3.2.5-1 Boric Acid Solubility Limit

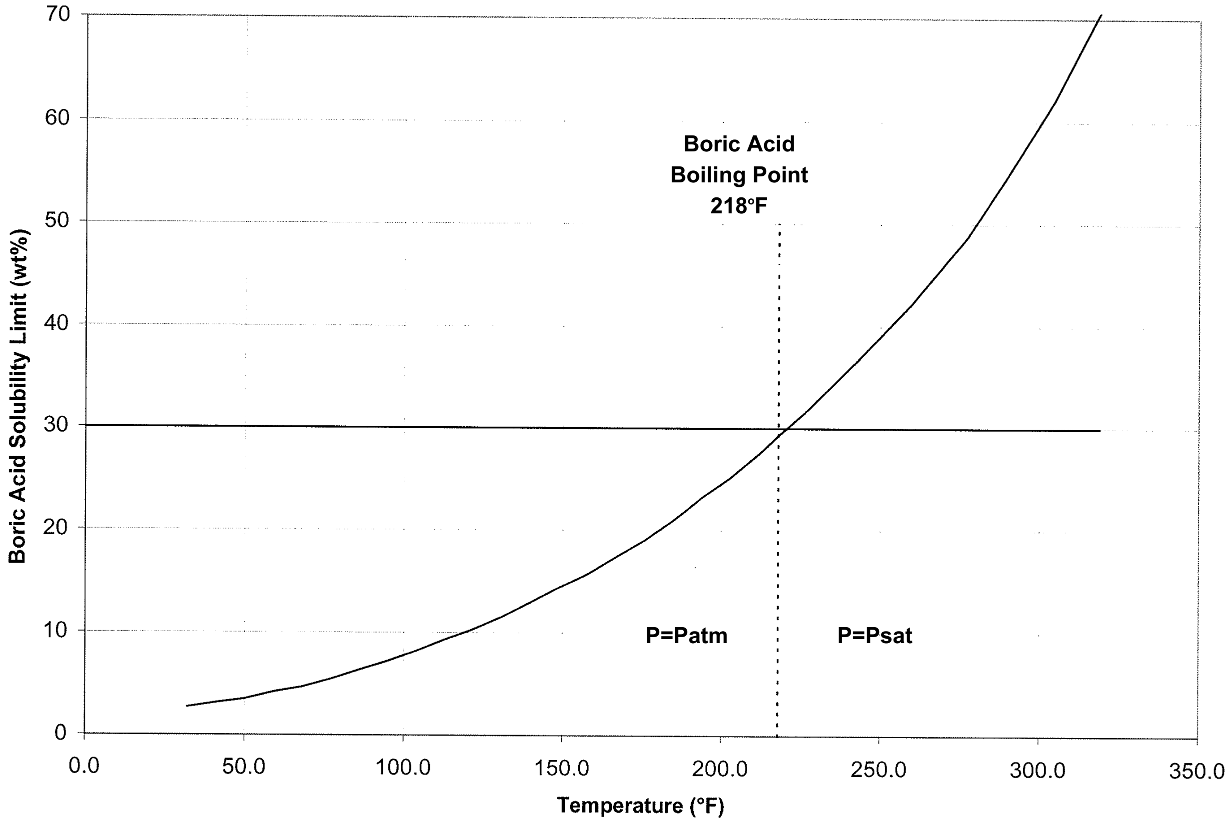


Figure 2.8.5.6.3.2.5-2
Post-LOCA Boric Acid Precipitation Control Plan

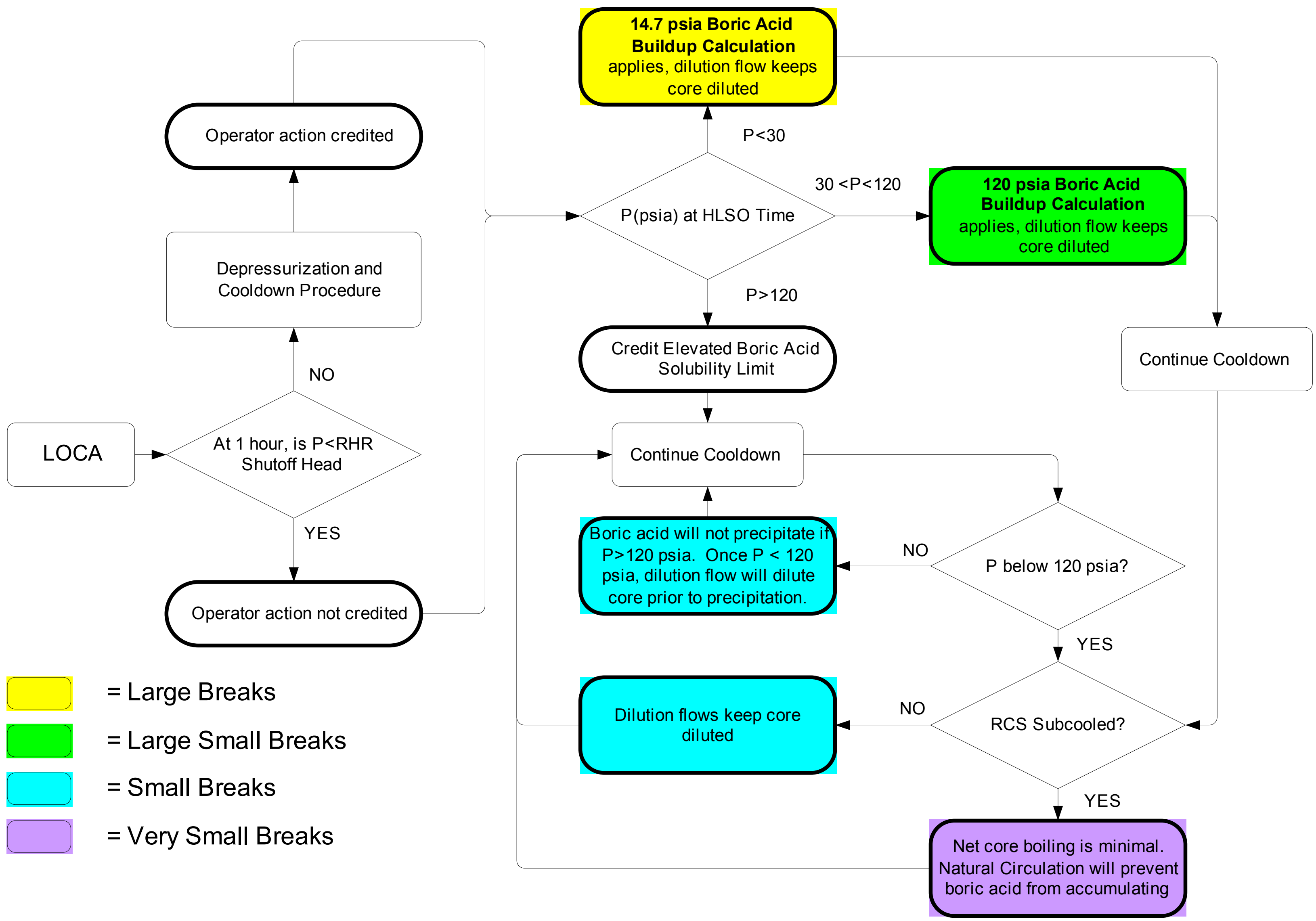


Figure 2.8.5.6.3.2.5-3
Boiloff, SI, and Core Dilution Rate at a 5 Hour HLSO Time at 14.7 psia

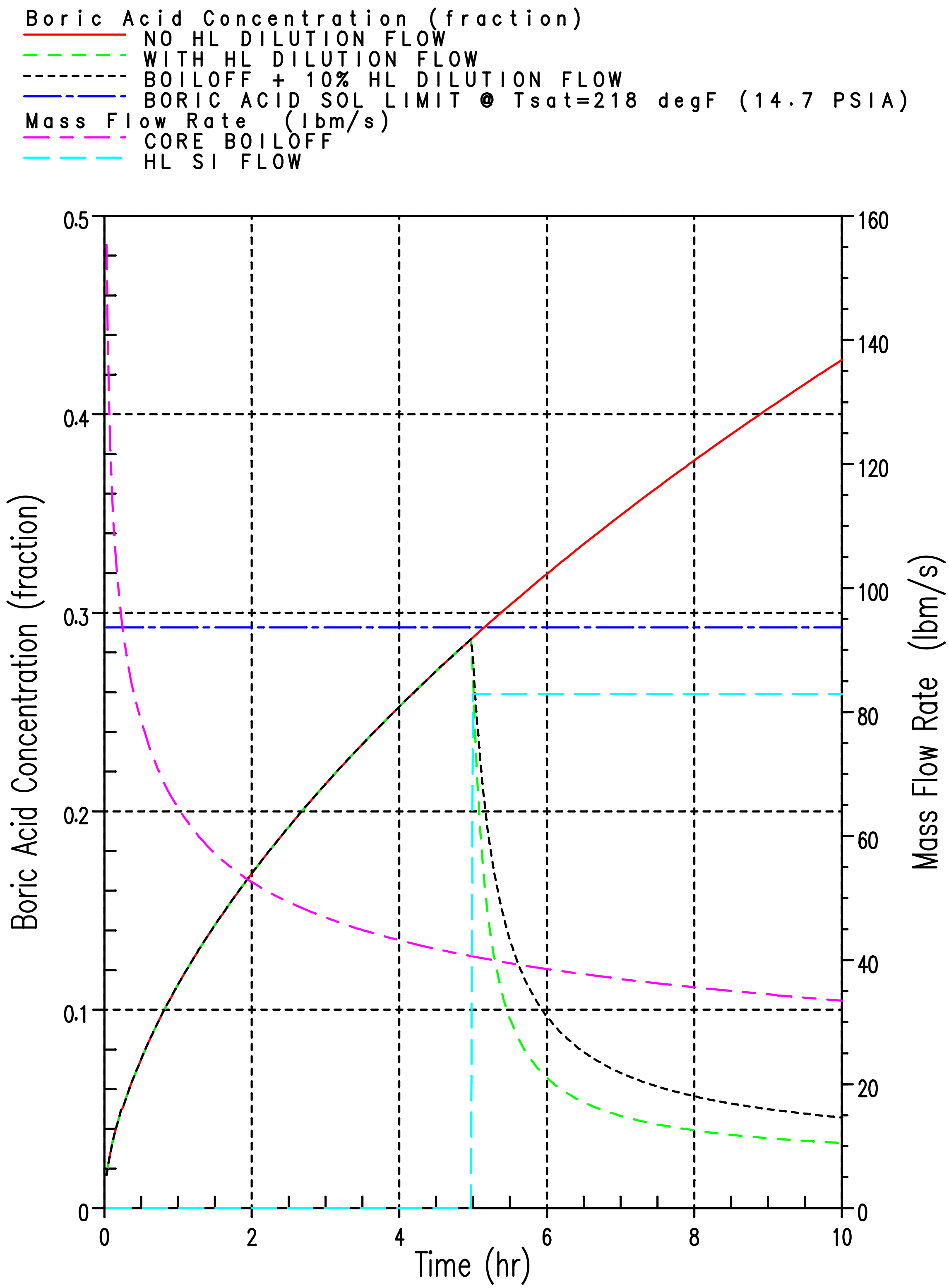


Figure 2.8.5.6.3.2.5-4
Boiloff, SI, and Core Dilution Rate at a 5 Hour HLSO Time at 120 psia

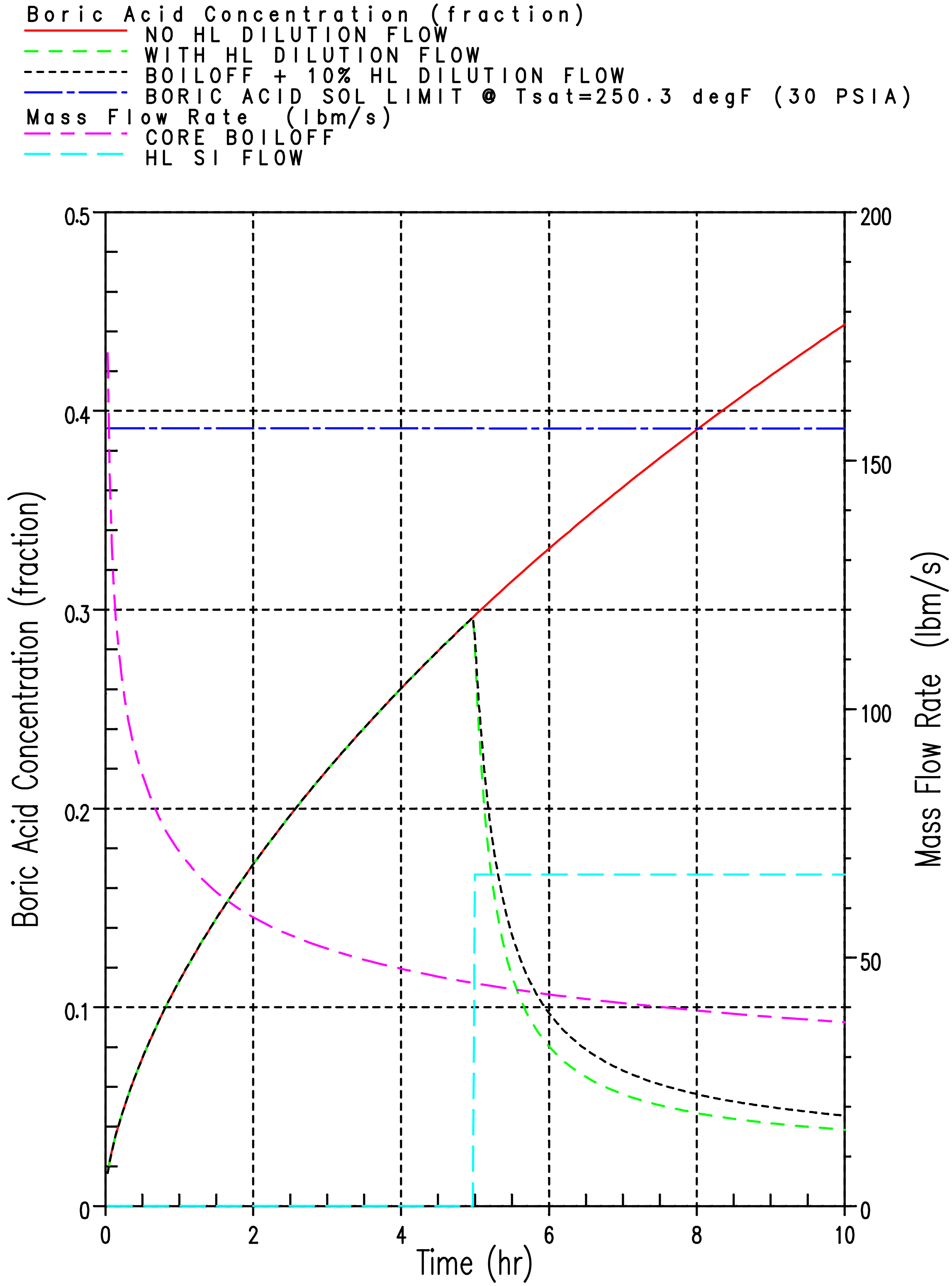
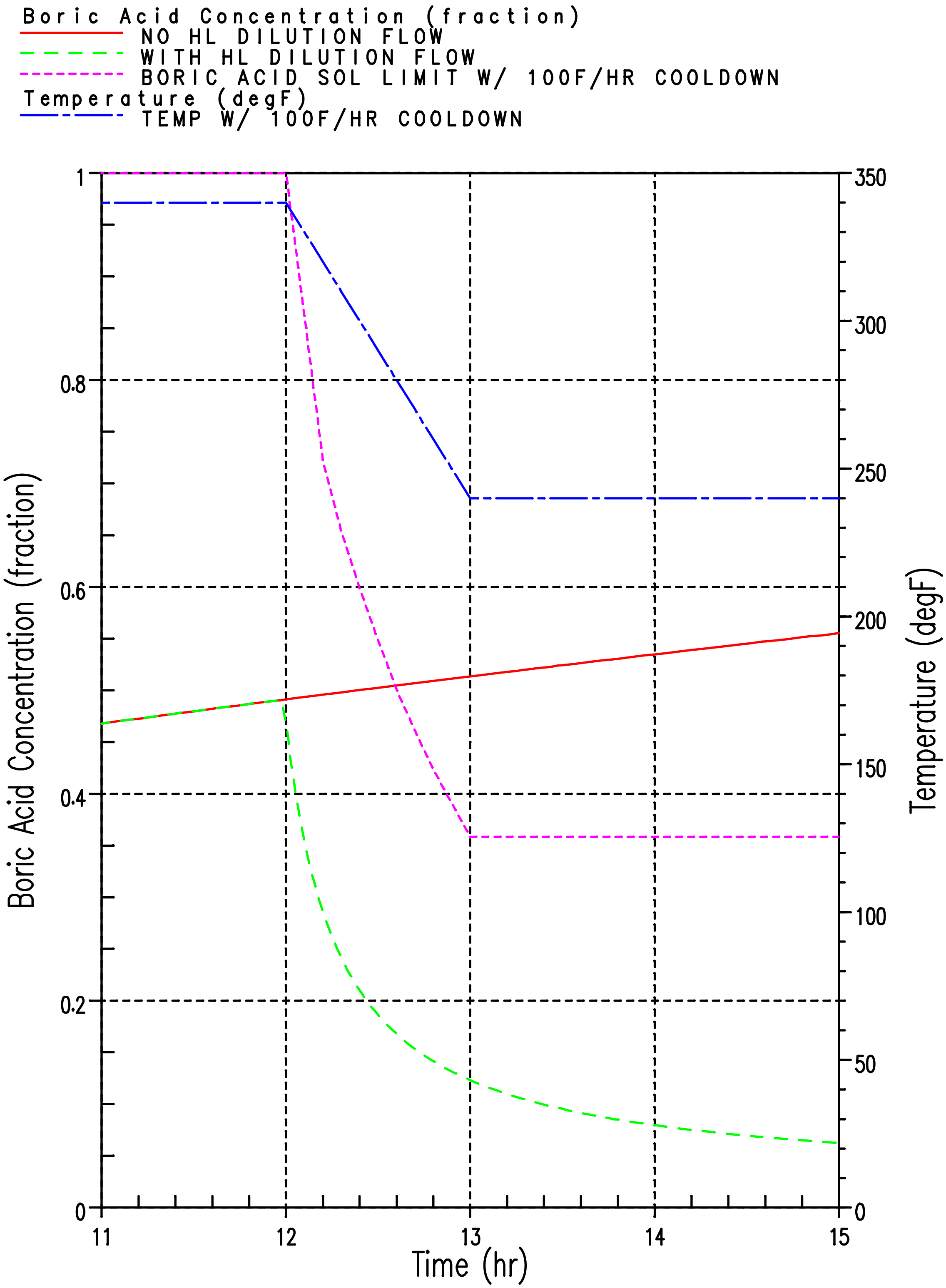


Figure 2.8.5.6.3.2.5-5
Demonstration of Core Dilution at 12 hours at 120 psia



2.8.5.7 Anticipated Transients Without Scrams

2.8.5.7.1 Regulatory Evaluation

ATWS is defined as an anticipated operational occurrence followed by the failure of the reactor trip portion of the protection system. NRC regulation 10 CFR 50.62 requires that:

- Each PWR must have equipment that is diverse from the reactor trip system to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must perform its function in a reliable manner and be independent from the existing reactor trip system, and

The DNC review was conducted to ensure that:

- The above requirements were met, and
- The setpoints for the ATWS mitigating system actuation circuitry (AMSAC) remain valid for the SPU.

MPS3 is a Westinghouse plant and is not required to install a DSS. In addition, for plants where a DSS is not specifically required by 10 CFR 50.62, verification is required to ensure that the consequences of an ATWS are acceptable. DNC verified that the consequences of an ATWS are acceptable for MPS3. The acceptance criterion is that the peak primary system pressure should not exceed the ASME B&PV Code Service Level C limit of 3200 psig. The peak ATWS pressure is primarily a function of the moderator temperature coefficient (MTC) and the primary system relief capacity. DNC reviewed

- The limiting event determination
- The sequence of events
- The analytical model and its applicability
- The values of parameters used in the analytical model
- The analyses results

DNC reviewed the justification of the applicability of generic vendor analyses to MPS3 and the operating conditions for the SPU. Review guidance is provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The final ATWS rule (10 CFR 50.62(c)(1)) requires the incorporation of a system to provide diverse (from the reactor trip system) actuation of the AFW system and turbine trip for Westinghouse designed plants. The installation of the NRC approved AMSAC system, described in FSAR Section 7.8.1.1, satisfies the final ATWS Rule. The bases for this rule and the AMSAC design are supported by Westinghouse analyses documented in Westinghouse letter NS-TMA-2182. For consistency with the basis of the Final ATWS Rule and the supporting analyses documented in NS-TMA-2182, the peak RCS pressure should not exceed the ASME B&PV Code Service Level C service limit stress criteria of 3200 psig. This value corresponds to the maximum allowable pressure for the weakest component in the RVP (the nozzle safe end).

There are no changes to the methods or acceptance criteria applied for ATWS in support of the SPU. The analysis of the ATWS event is described in FSAR Section 15.8.

In a letter dated October 14, 1986, the NRC staff indicated it had reviewed WOG topical report WCAP-10858 re: the AMSAC general design package. The NRC requested that MPS3 submit additional MPS3-specific information regarding compliance with 10 CFR 50.62, including the responses to a number of specific questions. This information was submitted to the NRC on April 20, 1988. In a letter dated July 17, 1989, the NRC issued a SER indicating its acceptance of MPS3's ATWS response.

MPS3 submitted a Technical Specification change request in a letter dated September 9, 1987, which proposed a positive moderator temperature coefficient (MTC) at reactor power levels less than 100 percent. The NRC forwarded a concern in a letter dated December 1, 1987, regarding an apparent trend to more positive MTC than those that were used by the PWR vendors in performing ATWS analyses. Specifically, the NRC requested an evaluation of the effects of the proposed MTC changes on the ATWS analysis applicable to MPS3. MPS3 responded in a letter dated January 7, 1988, indicating that for studies performed generically for the typical 4-loop plant design, the peak pressure resulting from an ATWS would be 3200 psig for a full power MTC of –5.5 PCM/°F; lower peak pressures would occur with more negative MTC values. An MPS3 specific assessment determined that, for MPS3 cycle 1, the full power MTC was more negative than –10.5 PCM/°F and, for cycle 2, was more negative than –7.6 PCM/°F. Both cycles satisfied the core reactivity assumptions. MPS3 has maintained the –5.5 PCM/°F limit for subsequent cycles.

The MPS3 ATWS related components (including AMSAC) were evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005 documents the results of that review. NUREG-1838 Sections 2.5.1 and 3.6 pertain to electrical and I&C systems – cables and connectors, which includes ATWS components.

2.8.5.7.2 Technical Evaluation

2.8.5.7.2.1 Introduction

The final ATWS Rule, 10 CFR 50.62(c)(1), requires the incorporation of a diverse (from the reactor trip system) actuation of the AFW system and turbine trip for Westinghouse-designed plants (Reference 1). The installation of the NRC-approved AMSAC satisfies this Final ATWS Rule. The basis for this rule and the AMSAC design are supported by Westinghouse analyses documented in NS-TMA-2182 (Reference 5). These analyses were performed based on guidelines published in NUREG-0460 (Reference 6).

NS-TMA-2182 also references WCAP-8330 (Reference 4) and subsequent related documents, which formed the initial Westinghouse submittal to the NRC for ATWS, and which were based on the guidelines set forth in WASH-1270 (Reference 7). For operation at SPU conditions, the Westinghouse generic ATWS analyses (Reference 5) were evaluated for their continued applicability.

NS-TMA-2182 describes the methods used in the analysis and provides reference analyses for two-loop, three-loop, and four-loop plant designs with several different steam generator models available in plants at that time. The reference analysis results demonstrated that the Westinghouse plant designs would satisfy the criteria in NUREG-0460.

The failure of the reactor scram is presumed to be a common mode failure of the control rods to insert into the core. The assumption of this common mode failure is beyond the requirement to address a single failure in the typical FSAR transient analyses. In addition, the methodology of NS-TMA-2182 uses control-grade equipment to mitigate consequences of the event, and uses nominal system performance characteristics in the evaluation of the event.

2.8.5.7.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The loss of load (LOL) and loss of normal feedwater (LONF) ATWS events are the two most limiting RCS overpressure transients reported in NS-TMA-2182. To address the SPU, these two events were analyzed at the SPU conditions to ensure that the basis for the final ATWS rule continues to be met.

The primary input to the LOL and LONF ATWS analysis for the SPU was the reference four-loop LOL and LONF ATWS models with Model F steam generators supporting NS-TMA-2182. The following analysis assumptions were used:

- The nominal and initial conditions were updated to the SPU NSSS design parameters for 3666 MWt documented in Table 1-1.
- Consistent with the analysis basis for the Final ATWS Rule (NS-TMA-2182):
  - Thermal Design Flow (TDF) is assumed, no uncertainties are applied to the initial power, RCS average temperature, or RCS pressure.
  - 0 percent steam generator tube plugging (SGTP) is assumed. 0 percent SGTP is more limiting
    (i.e., results in a higher peak RCS pressure) for ATWS events.
  - Control rod insertion was not assumed.
  - The AMSAC actuation setpoint is not directly assumed in the ATWS analyses. The analyses model turbine trip and actuation of the AFW system as a result of an AMSAC signal, not the AMSAC signal itself. This is consistent with the generic analysis. Refer to Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems for the discussion on AMSAC.

- The following plant-specific AFW flow input as a function of SG pressure was assumed, with an additional 30 second delay in the actuation of AFW for a total AFW delay of 90 seconds.

SG Pressure (psia)	AFW flow (gpm per SG)
0.	225.5
400.	225.5
450.	232.
500.	242.
550.	244.5
615.	246.5
1000.	247.
1100.	231.5
1236.	189.
1320.	155.

- The ATWS evaluation for the SPU assumed a plant-specific MTC of -7 pcm/°F, that bounds 95 percent of the cycle. This is more restrictive than and replaces the previous commitment to maintain an MTC more negative that -5.5 pcm/°F for 95 percent of the cycle. An MTC of -7 pcm/°F is confirmed on a cycle specific basis.

The Final ATWS Rule, 10 CFR 50.62(c)(1) (Reference 1), requires the incorporation of a diverse (from the reactor trip system) actuation of the AFW system and turbine trip for Westinghouse-designed plants. The installation of the NRC-approved AMSAC design satisfies this Final ATWS Rule. The bases for this rule and the AMSAC design are supported by Westinghouse analyses documented in NS-TMA-2182. To remain consistent with the basis of the Final ATWS Rule and the supporting analyses documented in NS-TMA-2182, the peak RCS pressure reached in the Millstone SPU ATWS evaluation should not exceed the ASME B&PV Code, Service Level C stress limit criterion of 3200 psig. This value corresponds to the maximum allowable pressure for the weakest component in the reactor pressure vessel (RPV) (the nozzle safe end).

2.8.5.7.2.3 Description of Analyses and Evaluations

An analysis was performed to assess the effect of the SPU on the reference four-loop LOL and LONF ATWS analyses with Model F steam generators documented in NS-TMA-2182. The analysis included revision of the reference four-loop LOL and LONF ATWS models with Model F steam generators to reflect the plant conditions at an NSSS power level of 3666 MWt. The LOFTRAN computer was used to perform the MPS3 ATWS analysis for the SPU, consistent with the analysis basis for the Final ATWS Rule. The use of LOFTRAN is also consistent with the analysis basis for FSAR Section 15.8.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The ATWS analysis is not within the scope of license renewal since it is an analytical product of a postulated event. NUREG-1838 Sections 2.5.1 and 3.6 pertain to electrical and I&C systems – cables and connectors, which includes ATWS components. The impact of the SPU on these components is discussed in Section 2.3.1, Environmental Qualification of Electrical Equipment.

SPU activities do not add any new components nor do they introduce any new functions for existing plant components relied upon to mitigate the effects of postulated ATWS events that would change the license renewal evaluation boundaries. The system and component performance capability in response to postulated ATWS events described in this section involves analytical techniques and methodology which are unaffected by the proposed SPU, and the results of remain bounded by the acceptance criteria of 10 CFR 50.62.

2.8.5.7.2.4 Results

The results of the ATWS analysis for Millstone with an NSSS power of 3666 MWt showed that the peak RCS pressure obtained in the LOL and LONF ATWS events, is 3105 psia and 2979 psia, respectively. Comparison of the Millstone SPU LOL and LONF ATWS results with the results from NS-TMA-2182 for the four-loop LOL and LONF ATWS models with Model F steam generators are provided below in Table 2.8.5.7.3-1. Although the results obtained for the SPU are more limiting than those documented in NS-TMA-2182, the peak RCS pressure did not exceed the B&PV Code, Service Level C stress limit criterion of 3215 psia (3200 psig). As such, the analytical basis for the Final ATWS Rule continues to be met for operation of Millstone at an NSSS power of 3666 MWt.

Time sequence of events tables are provided in Table 2.8.5.7.3-2 and 2.8.5.7.3-3 the SPU LOL and LONF ATWS, respectively. Figure 2.8.5.7-1 through 2.8.5.7-8 provide transient plots for the SPU LOL and LONF ATWS are provided in Figure 2.8.5.7-1 through 2.8.5.7-8.

To remain consistent with the basis of the Final ATWS Rule and the supporting analyses documented in NS-TMA-2182, the peak RCS pressure reached in the Millstone SPU ATWS evaluation should not exceed the ASME B&PV Code Service Level C stress limit criterion of 3200 psig. This value corresponds to the maximum allowable pressure for the weakest component in the RPV (the nozzle safe end).

The results of the LOL and LONF ATWS evaluation, using the revised reference four-loop LOL and LONF ATWS models at an NSSS power of 3666 MWt with Model F steam generators, demonstrated that the resulting peak RCS pressures are lower than the ASME B&PV Code Service Level C stress limit criterion of 3200 psig. Therefore, the analytical basis for the Final ATWS Rule continued to be met for operation of Millstone for the SPU.

2.8.5.7.3 Conclusion

DNC has reviewed the information related to ATWS and concludes that it has adequately accounted for the proposed SPU effects on ATWS. DNC concludes that the evaluation has demonstrated that the AMSAC continues to meet the requirements of 10 CFR 50.62 following SPU implementation. The evaluation has shown that the plant is not required by 10 CFR 50.62 to have a diverse scram system. Additionally, the evaluation has demonstrated that the peak primary system pressure following an ATWS event remains below the acceptance limit of 3200 psig. Therefore, DNC finds the proposed SPU acceptable with respect to ATWS.

2.8.5.7.3.1 References

1. 10 CFR 50.62, Requirements for Reduction of Risk from ATWS Events for Light Water-Cooled Nuclear Power Plants.

2. ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers.

3. WCAP-10858, AMSAC Generic Design Package, June 1985.

4. WCAP-8330, Westinghouse Anticipated Transient Without Trip Analysis, August 1974.

5. NS-TMA-2182, Anticipated Transients Without Scram for Westinghouse Plants, December 1979.

6. NUREG-0460, Anticipated Transients Without Scram for Light Water Reactors, April 1978.

7. NRC Report WASH-1270, Technical Report on Anticipated Transients Without Scram for Water Cooled Power Reactors, September 1973.

8. NRC Letter issuing the SER indicating NRC’s acceptance of MPS3’s ATWS response, July 17, 1989.

Table 2.8.5.7.3-1
Comparison of Peak RCS Pressure

	Peak RCS Pressure, psia	
Event	Millstone SPU Results	NS-TMA-2182 Model F SGs Results
Loss of Load	3104.8	2902.0
Loss of Normal Feedwater	2978.6	2830.0

Table 2.8.5.7.3-2
Time Sequence of Events
Loss of Load ATWS

Event	Time (sec)
Turbine trip occurs	1.0
FW flow terminated	4.0
AFW initiated	90.0
Peak RCS Pressure (3104.8 psia) reached [versus RCS pressure limit of 3215 psia]	106.0

Table 2.8.5.7.3-3
Time Sequence of Events
Loss of Normal Feedwater ATWS

Event	Time (sec)
FW flow terminated	4.0
Turbine trip	30.0
AFW initiated	90.0
Peak RCS Pressure (2978.6 psia) reached [versus RCS pressure limit of 3215 psia]	95.0

Figure 2.8.5.7-1
Nuclear Power and Core Heat Flux versus Time for LOL ATWS

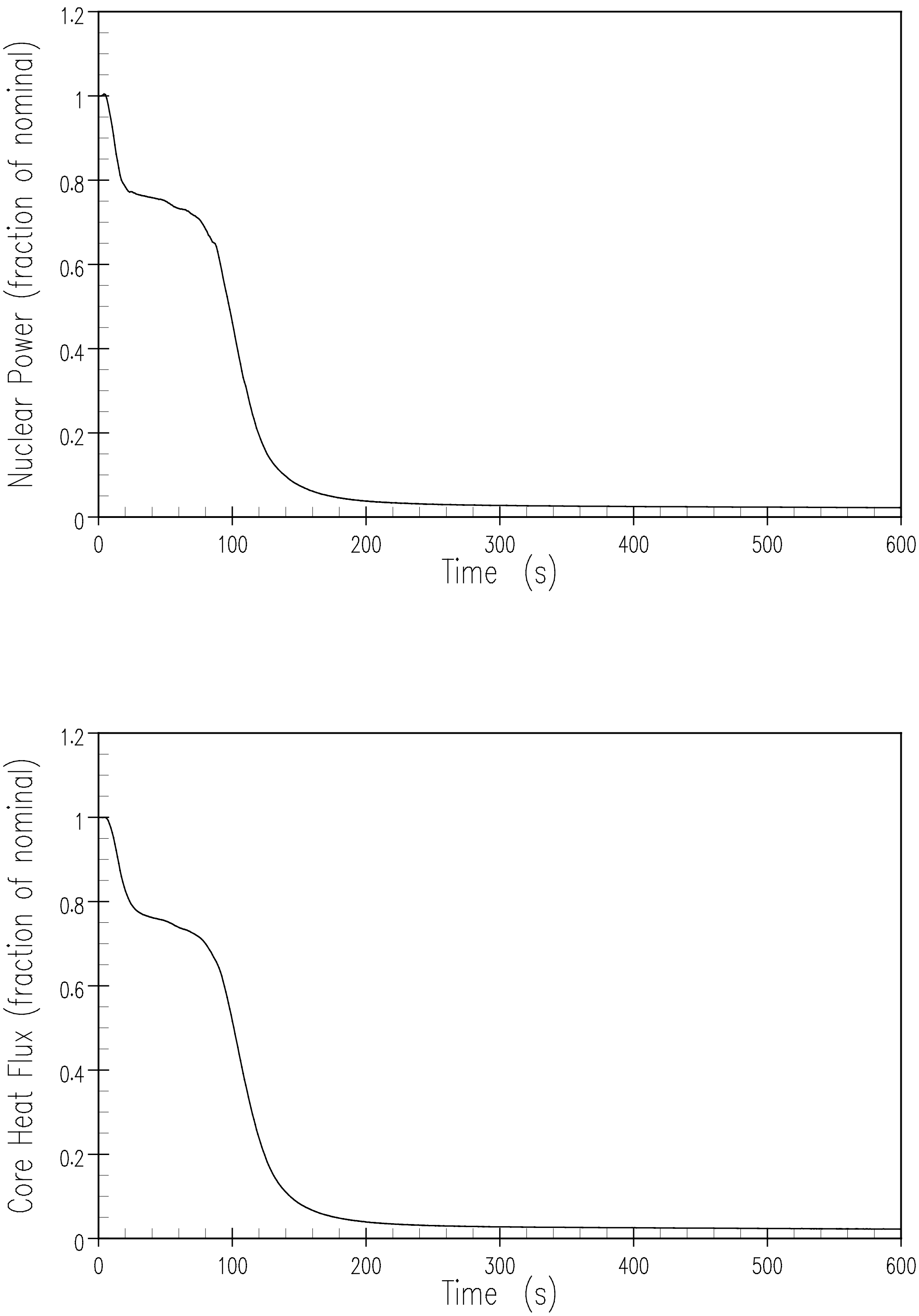
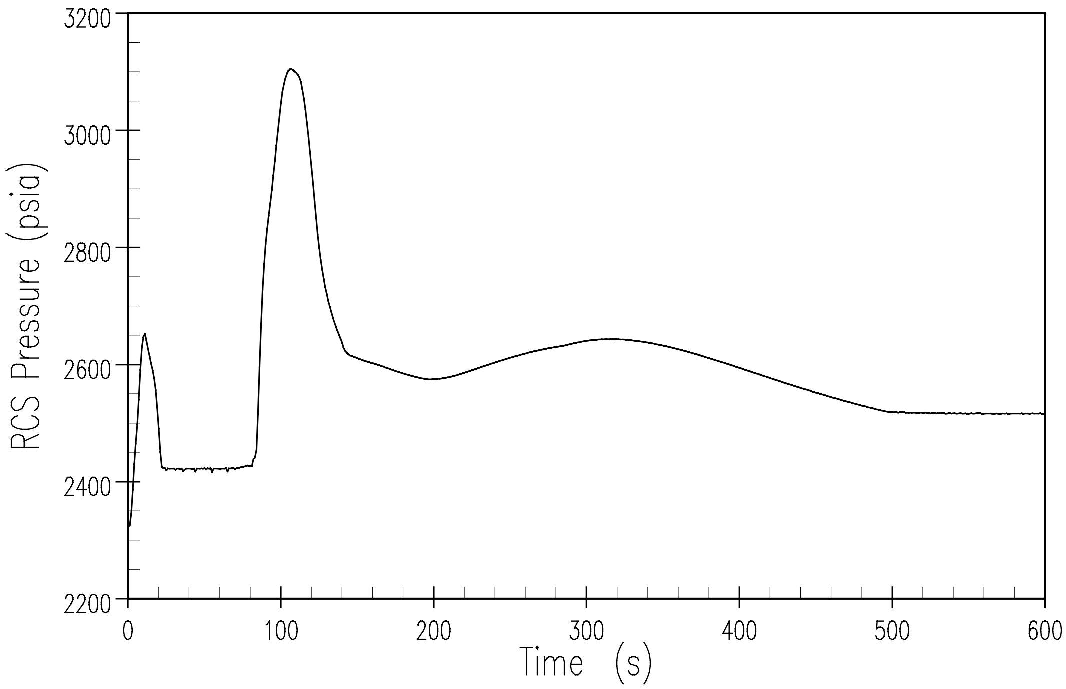


Figure 2.8.5.7-2
RCS Pressure and Pressurizer Water Volume versus Time for LOL ATWS



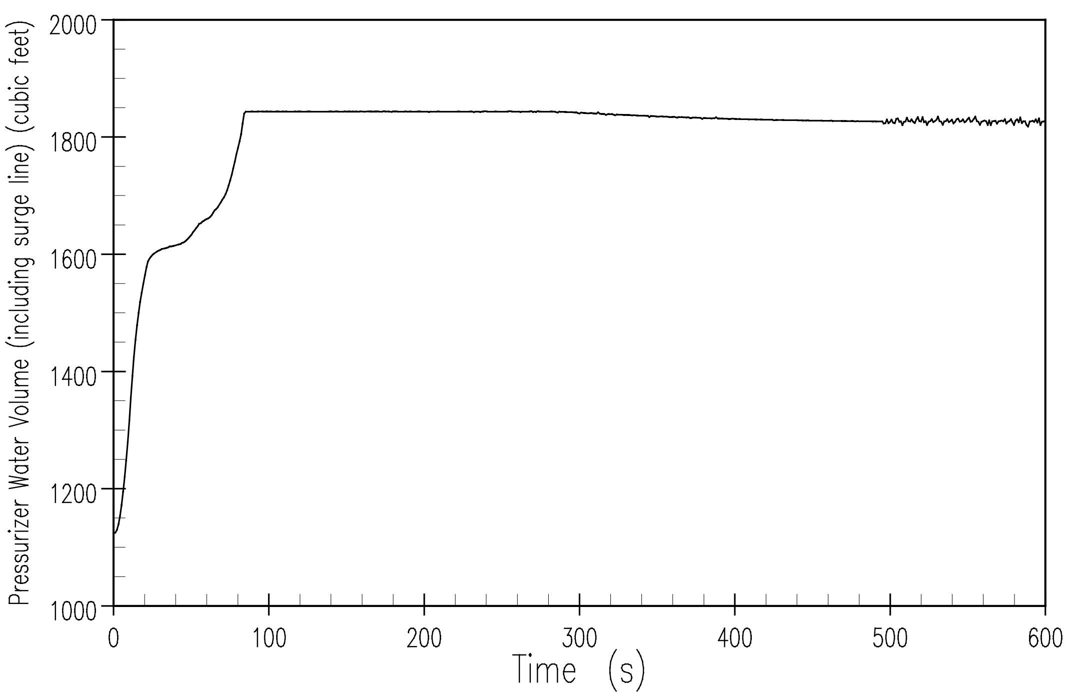


Figure 2.8.5.7-3
Vessel Inlet Temperature and RCS Flow versus Time for LOL ATWS

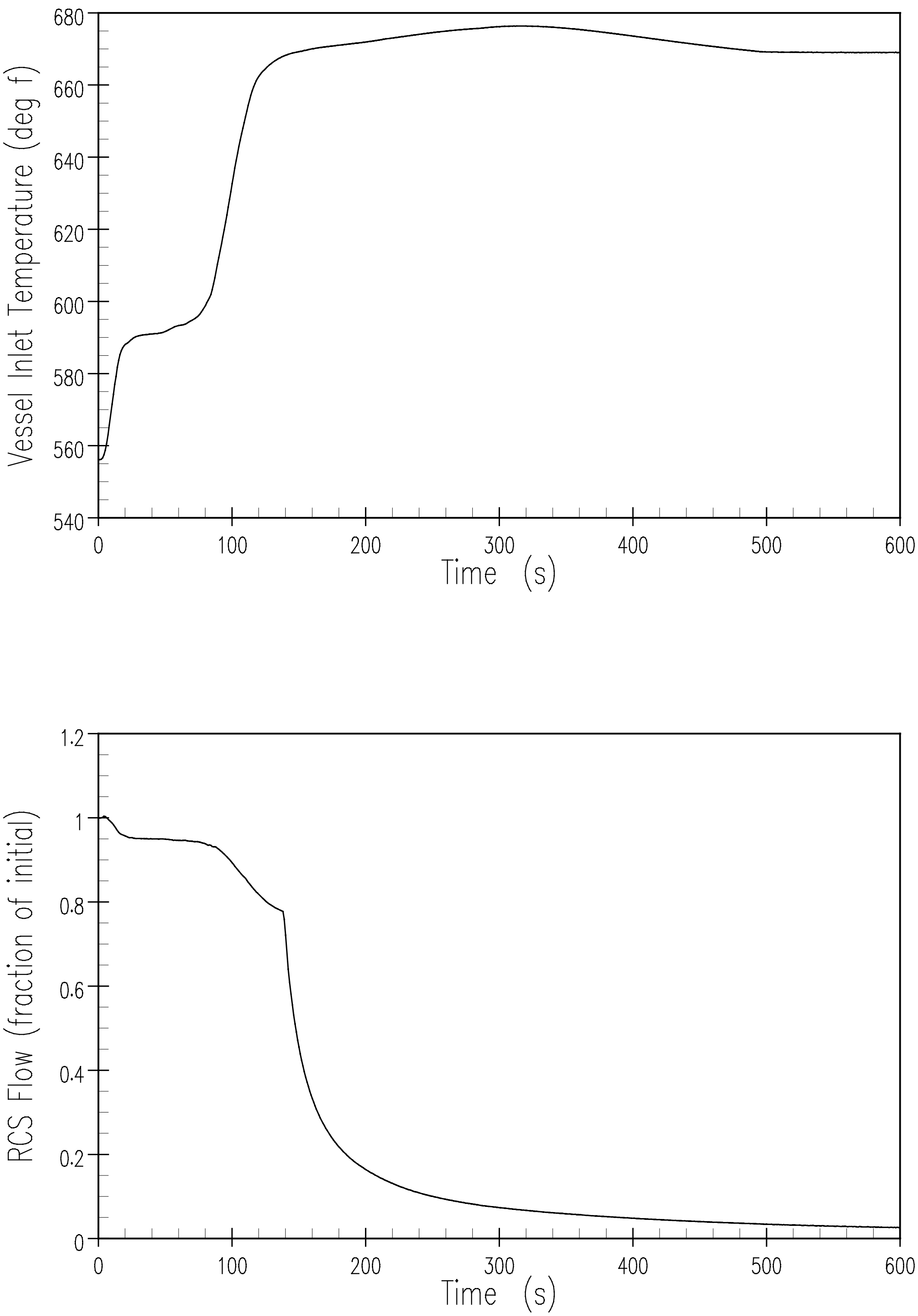
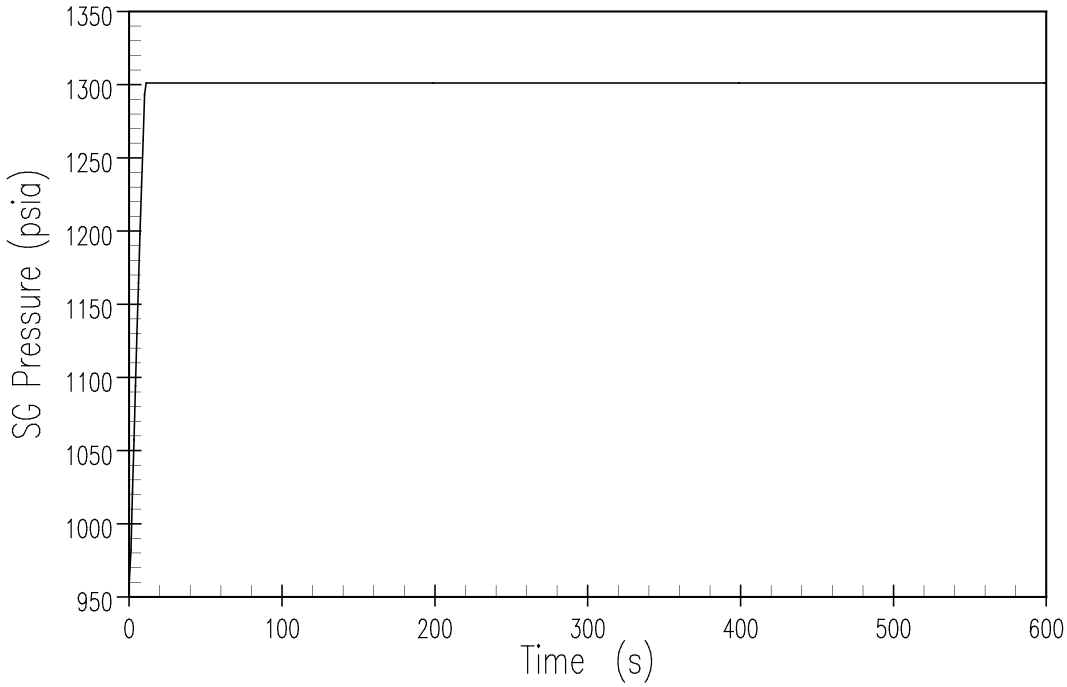


Figure 2.8.5.7-4
SG Pressure and SG Mass versus Time for LOL ATWS



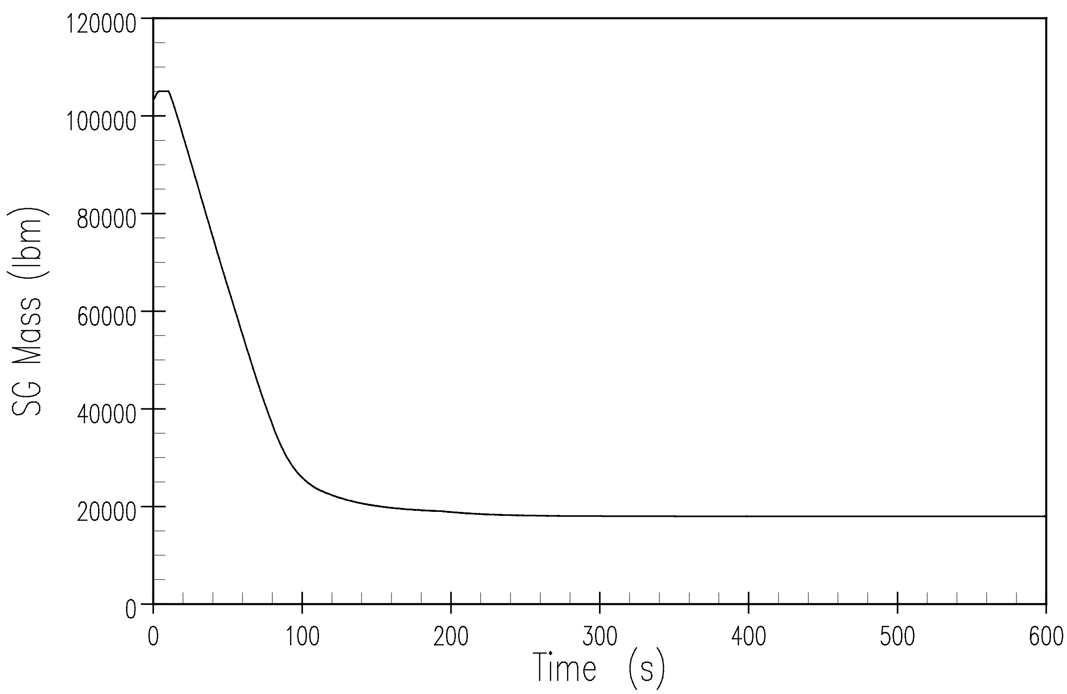
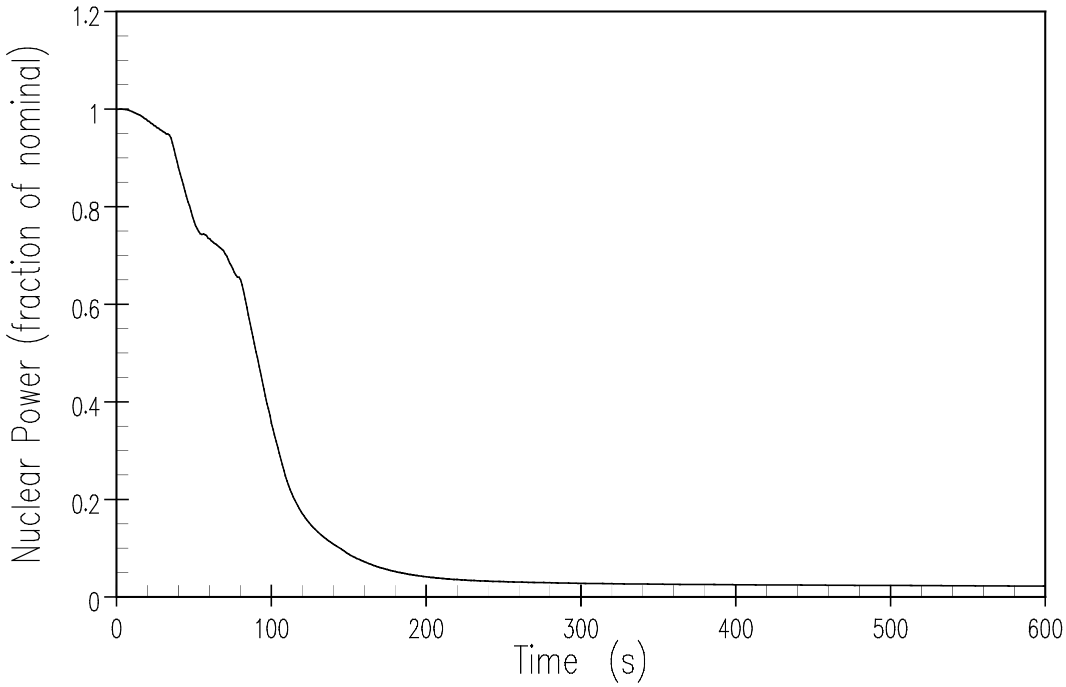


Figure 2.8.5.7-5
Nuclear Power and Core Heat Flux versus Time for LONF ATWS



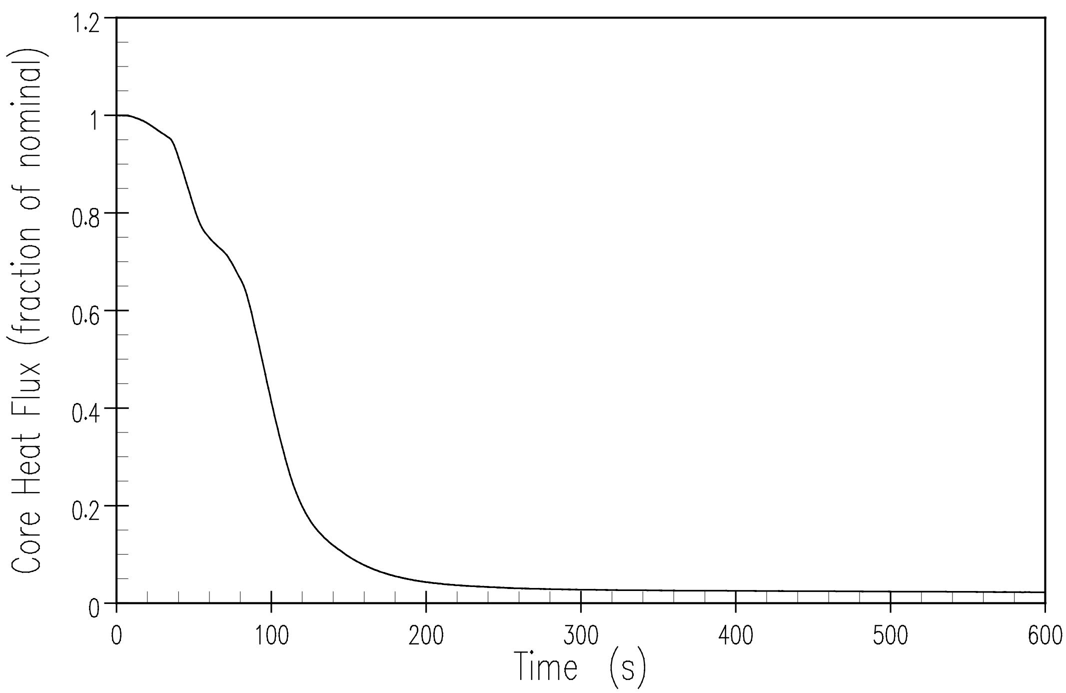
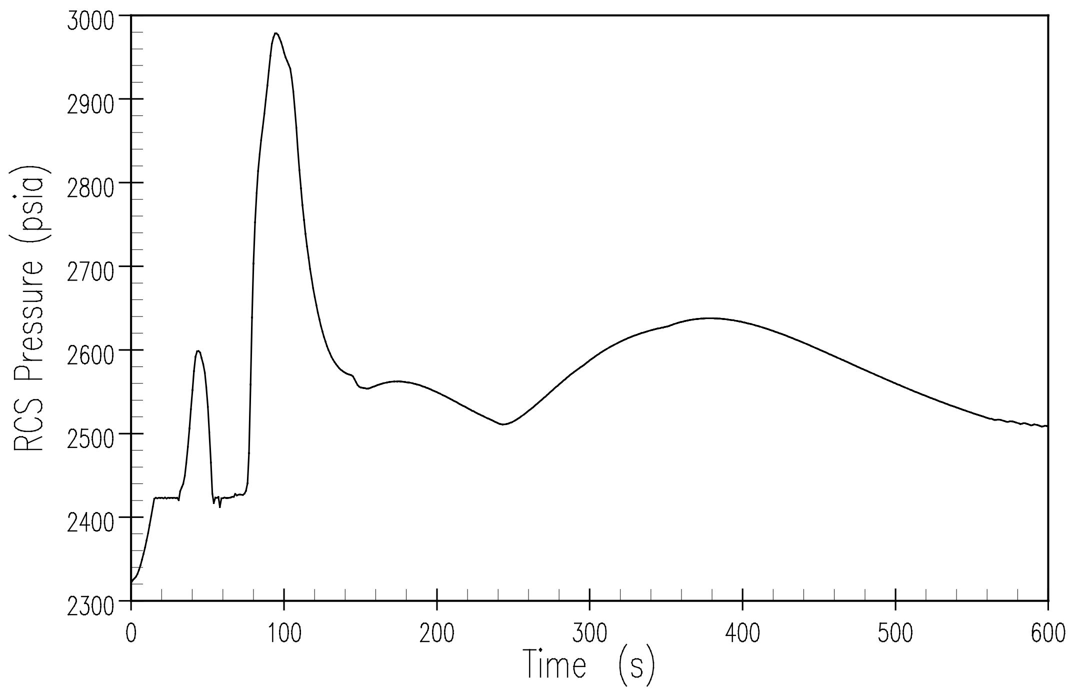


Figure 2.8.5.7-6
RCS Pressure and Pressurizer Water Volume versus Time for LONF ATWS



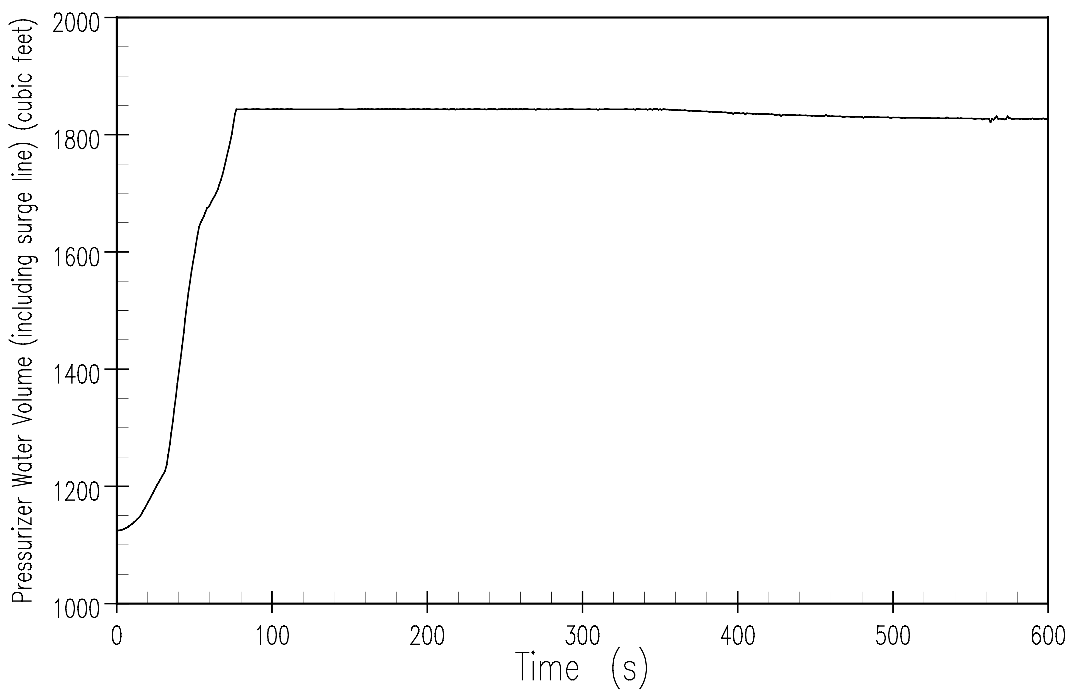


Figure 2.8.5.7-7
Vessel Inlet Temperature and RCS Flow versus Time for LONF ATWS

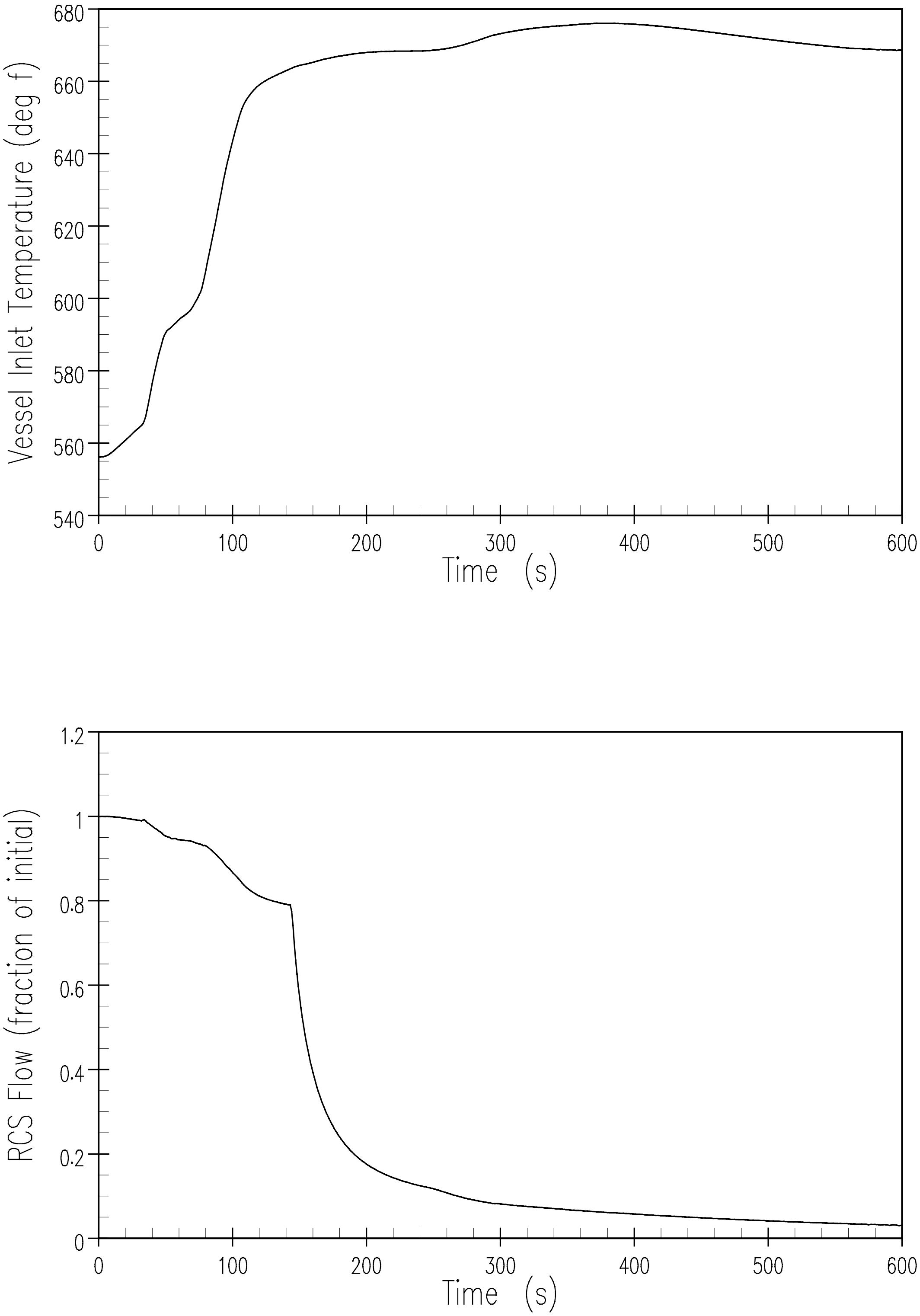
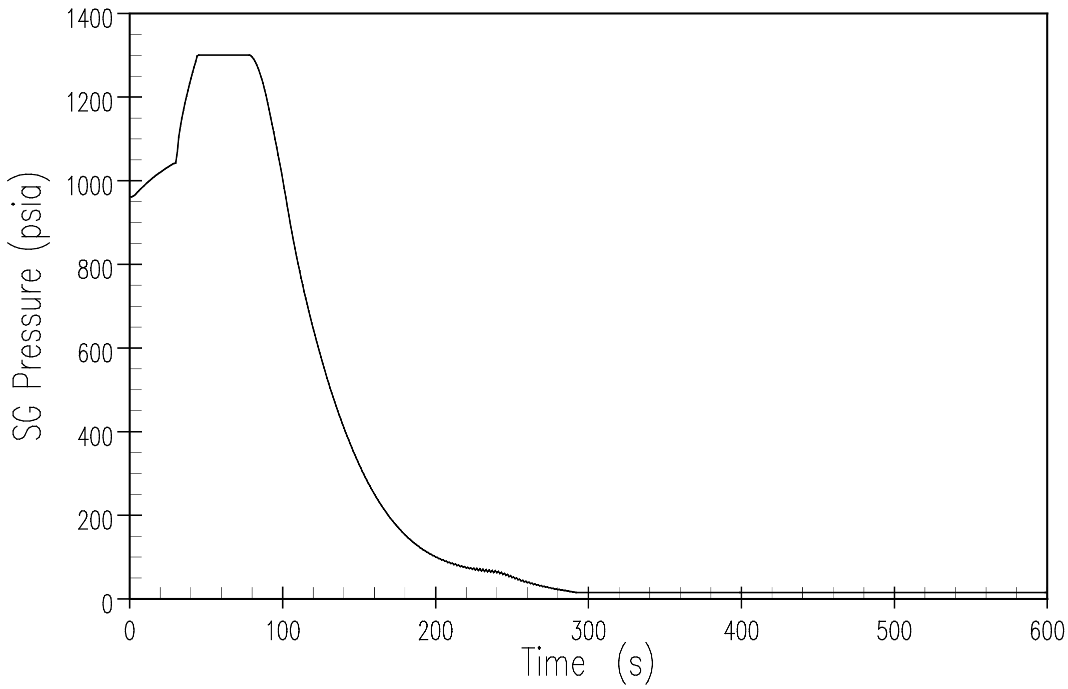
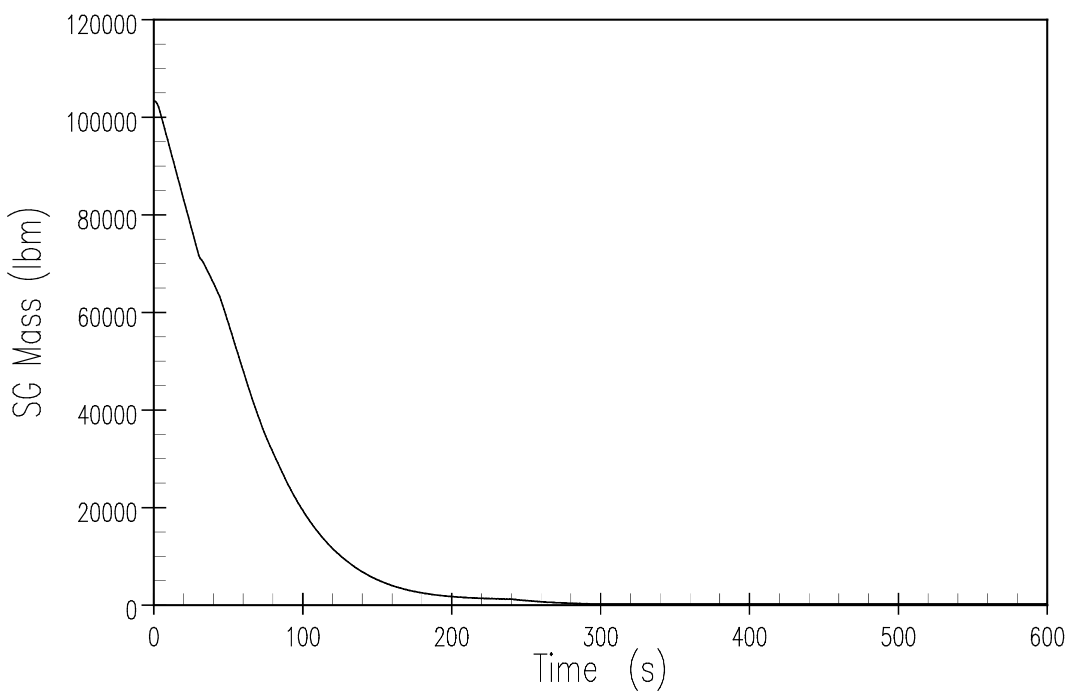


Figure 2.8.5.7-8
SG Pressure and SG Mass versus Time for LONF ATWS





2.8.6 Fuel Storage

2.8.6.1 New Fuel Storage

2.8.6.1.1 Regulatory Evaluation

Nuclear power plants include facilities for the storage of new fuel. The quantity of new fuel stored varies from plant to plant, depending on the specific design of the plant and individual refueling needs. The DNC review covered the ability of the storage facilities to maintain the new fuel in a subcritical array during all credible storage conditions

The acceptance criteria are based on:

- GDC-62, insofar as it requires that criticality in the fuel storage and handling system be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

Specific review criteria are contained in SRP Section 9.1.1 and the guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981(NUREG-0800), SRP Section 9.1.1, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the GDC is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 new fuel storage regarding conformance to

- GDC-62 is described in MPS3 UFSAR Section 3.1.2.62, General Design Criterion 62 - Prevention of Criticality in Fuel Storage and Handling.

  Criticality is prevented in the new fuel storage racks by a combination of geometry and poison materials, as described in FSAR Sections 9.1.1 and 4.3.2.6.

The new fuel storage vault facility has a total storage capacity of 96 fuel assemblies. The design and safety evaluation of the new fuel dry storage racks is in accordance with the NRC position paper, “Review and Acceptance of Spent Fuel Storage Handling Applications,” dated April 1978.

The racks are designated ANS Safety Class 3 and Seismic Category 1 and are designed to withstand normal and postulated dead loads, live loads, and loads caused by the operating basis earthquakes and safe shutdown earthquake events.

For new fuel storage, the design basis for preventing criticality is that, considering possible variations, there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor (K_{eff}) of the fuel assembly array when the new fuel racks are fully loaded with maximum reactivity fuel will be:

- less than or equal to 0.95 when flooded with potential moderators; and
- less than or equal to 0.98 when surrounded by optimum moderation.

Fuel barriers and the close spacing of the cells prevent inserting a fuel assembly in other than design locations or between the rack periphery and the pool wall.

The racks are also designed with adequate energy absorption capabilities to withstand the impact of a dropped fuel assembly from the maximum lift height of 5 feet over the top of the racks. The fuel storage racks can withstand an uplift force equal to 2000 pounds.

All materials used in construction are compatible with the Fuel building/vault environment, and all surfaces that come into contact with the fuel assemblies are made of annealed austenitic stainless steel. All the materials are corrosion resistant and do not contaminate the fuel assemblies or vault environment.

The MPS3 new fuel storage was evaluated for continued acceptability to support plant license renewal. NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.4B.2.4 and 3.5B.2.3.5 are applicable to new fuel storage.

2.8.6.1.2 Technical Evaluation

DNC has reviewed the potential effects of the SPU for MPS3, and this review has identified the following: (1) There are no fuel design changes implemented in support of the SPU, (2) there is no increase in the Technical Specification maximum allowed fuel enrichment (5.0 w/o U-235) for the SPU, and (3) there are no modifications to the New Fuel Storage Vault for the SPU. Therefore, DNC concludes that the criticality analysis of record for the new fuel storage vault remains valid for the SPU for MPS3. Hence, no additional analysis is required.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

The MPS3 new fuel storage is within the scope of License Renewal as identified in NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” Sections 2.4B.2.4 and 3.5B.2.3.5. SPU activities are not changing the fuel design, not changing the maximum fuel enrichment, not adding any new components within the existing license renewal scoping evaluation boundaries, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The SPU conditions do not add any new or previously unevaluated materials to the new fuel storage system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.8.6.1.3 Conclusion

DNC has reviewed whether there are any potential effects from the SPU for MPS3 on the analyses of record for the new fuel storage facility, and concludes that no additional analyses are required. The new fuel storage facilities will continue to meet the requirements of GDC-62 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to new fuel storage.

2.8.6.2 Spent Fuel Storage

2.8.6.2.1 Regulatory Evaluation

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the SFP and storage racks is to maintain the spent fuel assemblies in a safe and subcritical array during all credible storage conditions and to provide a safe means of loading the assemblies into shipping casks. The DNC review covered the effect of the proposed SPU on the criticality analysis (e.g., reactivity of the spent fuel storage array and boraflex degradation or neutron poison efficacy).

The acceptance criteria are based on:

- GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.
- GDC-62, insofar as it requires that criticality in the fuel storage and handling system be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

Specific review criteria are contained in SRP Section 9.1.2 and the guidance provided in Matrix 8 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with the July 1981 edition of the Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants (NUREG-0800), SRP Section 9.1.2, Rev. 3.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC GDC for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the GDC is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 spent fuel storage regarding conformance to:

- GDC-4 is described in the FSAR Section 3.1.2.4, General Design Criterion 4 - Environmental and Missile Design Bases.

  SSC important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operating, maintenance, testing, and postulated accidents including LOCAs. These items are either protected from accident conditions or designed to withstand, without failure, exposure to the combination of temperature, pressure, humidity, radiation, and dynamic effects expected during the required operational period.

  Physical separation, physical protection, pipe restraints, and redundancy are included in the design of safety-related systems to ensure that each such system performs its intended safety function.

SSCs important to safety are classified as QA Category I and are designed in accordance with the codes and classifications indicated in the FSAR, Section 3.2.5.

FSAR Section 3.11 provides the details of the environmental activities and dynamic effects to which the SSCs important to safety are designed.

- GDC-62 is described in MPS3 UFSAR Section 3.1.2.62, General Design Criterion 62 - Prevention of Criticality in Fuel Storage and Handling.

  Criticality is prevented in the spent fuel storage area by the physical separation of fuel assemblies, limits on the enrichment, burnup and decay times of the fuel, and the use of fixed neutron poisons in Region 1 and 2. Soluble boron in the SFP water is credited for certain accident conditions. FSAR Sections 9.1.2 and 4.3.2.6 discuss criticality prevention in more detail.

MPS3 submitted a license amendment request on March 19, 1999 to increase the spent fuel storage capacity from 756 to 1860 fuel assemblies by installing additional spent fuel racks. The NRC issued Amendment 189 on November 28, 2000, approving this request. The spent fuel storage pool contains 350 Region 1 storage locations, 673 Region 2 storage locations and 756 Region 3 storage locations, for a total of 1779 total available fuel storage locations. An additional Region 2 rack with 81 storage locations may be placed in the spent fuel pool, if needed. With this additional rack installed, the Region 2 storage capacity is 754 storage locations, for a total of 1860 available fuel storage locations.

The design and safety evaluation of the spent fuel storage racks is in accordance with the NRC position paper, Review and Acceptance of Spent Fuel Storage and Handling Applications, dated April 1978. The racks are designated ANS safety Class 3 and Seismic Category I and are designed to withstand normal and postulated dead loads, live loads, loads due to thermal effects, and loads caused by the operating basis earthquakes and safe shutdown earthquake events.

All materials used in construction are compatible with the SFP environment, and all surfaces that come into contact with the fuel assemblies are made of annealed austenitic stainless steel. All the materials are corrosion resistant and do not contaminate the fuel assemblies or pool environment.

At the time MPS3 was first licensed, a full core off-load was categorized as an abnormal event. MPS3 submitted a license amendment request on January 18, 1999, to formalize a licensing basis change to reclassify the full core off-load as a normal evolution. This change also increased the maximum design basis normal SFP temperature from 140 °F to 150 °F. The NRC issued Amendment 182 on September 12, 2000 approving this request.

The design basis for preventing criticality in the spent fuel pool is that, considering possible variations, there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor (K_{eff}) of the fuel assembly array will be less than or equal to 0.95 as recommended in ANSI N210-1976. The design of the racks is such that K_{eff} meets this design basis under all conditions, including fuel handling accidents, seismic events, and loss of fuel pool cooling. No credit is taken for soluble boron except for accident conditions. The limiting accident condition is the inadvertent placement (or drop) of a single 5 weight percent fresh fuel assembly into a vacant Region 3 storage cell. Calculations have shown that 800 ppm of soluble boron in the pool water is sufficient to ensure K_{eff} will remain less than or equal to 0.95 under this condition. Technical Specifications require a minimum of 800 ppm boron concentration be maintained whenever fuel is stored in the SFP. For Region1 and 2, credit is taken for Boral neutron absorption. Region 3 takes no credit for neutron absorption by Boraflex.

MPS3 responded to NRC Generic Letter 96-04, Boraflex Degradation in Spent Fuel Pool Storage Racks, by letter dated October 24, 1996. MPS3 committed to periodically monitoring Boraflex degradation by performing Boraflex blackness testing and coupon testing, until Boraflex was no longer credited in the criticality analysis. Amendment 189 removed the credit for neutron absorption by Boraflex, thus eliminating the need for a Boraflex monitoring program.

MPS3 has chosen to comply with 10 CFR 50.68(b) concerning criticality accident requirements as documented in FSAR Section 9.1.

The MPS3 spent fuel storage was evaluated for continued acceptability to support plant license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.4B.2.4 and 3.5B.2.3.5 are applicable to spent fuel storage.

2.8.6.2.2 Technical Evaluation

2.8.6.2.2.1 Introduction

The purpose of this section is to describe the results of spent fuel pool criticality calculations due to the proposed SPU. All of the spent fuel storage racks in the Millstone 3 spent fuel pool were re-analyzed for the proposed SPU. This re-analysis was necessary because the reactivity of spent fuel stored in the spent fuel racks will be different, depending on the reactor core operating conditions present when the fuel was depleted in the reactor. There are no physical changes being made to the spent fuel pool or storage racks due to the SPU. The effects of the SPU on the spent fuel pool cooling system are evaluated in Section 2.5.4.1.

2.8.6.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The spent fuel pool criticality safety analysis utilizes input parameters that are appropriate for the proposed SPU of MPS3. Many of these input parameters are consistent with the current licensing basis. However, inputs parameters affected by the MPS3 SPU, such as core operating conditions, are updated appropriately. A complete list of the input parameters and assumptions utilized in the spent fuel pool criticality safety analysis is included in WCAP-16721-NP.

The acceptance criteria for the spent fuel pool criticality safety analysis require that there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor (K_{eff}) of the spent fuel pool will be less than 0.95 under all conditions. No credit is taken for soluble boron except for accident conditions.

2.8.6.2.2.3 Description of Analyses

The spent fuel pool criticality safety analysis determined the loading requirements for safe storage of fuel assemblies in the Region 1, Region 2, and Region 3 storage racks of the MPS3 spent fuel pool consistent with the current licensing basis. Reactivity credit for assembly burnup and Pu-241 decay is considered in the analysis. Soluble boron is not credited for normal storage of fuel in the spent fuel racks, nor is soluble boron credited for any normal spent fuel pool operating conditions. The effects of the most limiting postulated accident scenario are mitigated with soluble boron. All other accident scenarios are bounded by this accident. The analysis is described in detail in WCAP-16721-NP.

Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

The MPS3 spent fuel storage is within the scope of License Renewal as identified in NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, Sections 2.4B.2.4 and 3.5B.2.3.5. SPU activities are not changing the fuel design, not increasing the fuel enrichment, not adding any new components within the existing license renewal scoping evaluation boundaries, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The SPU conditions do not add any new or previously unevaluated materials to the spent fuel storage system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.8.6.2.2.4 Results

As shown in WCAP-16721-NP, the following are the results of the criticality re-analysis of all the fuel storage regions in the Millstone 3 Spent Fuel Pool:

- Region 1 3-out-of-4 fuel storage – The limiting fuel allowed in this region is 5 weight percent U-235 fresh fuel. The SPU does not affect the reactivity of 5 w/o U-235 fresh fuel. As described in WCAP-16721-NP, the analysis for this storage region confirms that there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor ($K_{eff)}$ will remain less than 0.95. This analysis does not credit soluble boron for normal storage conditions. The current Technical Specifications allow up to 5 weight percent fresh fuel, hence no Technical Specification changes are required for Region 1 3-out-of-4 fuel storage.
- Region 1 4-out-of-4 fuel storage – a curve of allowable fuel enrichment versus burnup for the SPU for this region is specified in WCAP-16721-NP. As described in WCAP-16721-NP, the analysis for this storage region confirms that there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor ($K_{eff)}$ will remain less than 0.95. This analysis does not credit soluble boron for normal storage conditions. The existing required Technical Specification curve of allowable enrichment versus burnup (TS Figure 3.9-1) for storage of fuel in this region for the current power level is more restrictive than the proposed curve for the SPU. As a result, the existing TS Figure 3.9-1 for Region 1 4-out-of-4 storage bounds both the existing licensed power level and the SPU and for conservatism, the existing TS figure will be retained. Therefore, no Technical Specification changes are required.
- Region 2 fuel storage – a curve of allowable fuel enrichment versus burnup and decay time for the SPU for this region is specified in WCAP-16721-NP. As described in WCAP-16721-NP, the analysis for this storage region confirms that there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor ($K_{eff)}$ will

remain less than 0.95. This analysis does not credit soluble boron for normal storage conditions. The proposed curve of allowable enrichment versus burnup and decay time for storage of fuel in this region for the SPU is more restrictive than the existing TS curve for Region 2 (TS Figure 3.9-3). As a result, the proposed Region 2 curve for allowable fuel enrichment versus burnup and decay time for the SPU must replace the existing TS Figure 3.9-3 for Region 2. Decay time credit for Region 2 is new, but has been previously approved by the NRC in the existing Region 3 of the Millstone 3 spent fuel pool. DNC determined that decay time credit for Region 2 was needed due to the SPU, to provide assurance that the ability to offload the core is maintained. If decay time credit was not used, than there is a higher likelihood that fuel may not meet the requirements for storage in Region 2 under the SPU, and therefore must be stored in Region 1. Region 1 fuel storage racks are needed to fully offload the core, and therefore any increased fuel storage required in Region 1 could affect the ability to offload the core.

- Region 3 fuel storage – a curve of allowable fuel enrichment versus burnup and decay time for the SPU for this region is specified in WCAP-16721-NP. As described in WCAP-16721-NP, the analysis for this storage region confirms that there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor (K_{eff}) will remain less than 0.95. This analysis does not credit soluble boron for normal storage conditions. The proposed curve of allowable enrichment versus burnup and decay time for storage of fuel in this region for the SPU is more restrictive than the existing TS curve for Region 3 (TS Figure 3.9-4). DNC has determined that it is appropriate to retain both the existing TS Figure 3.9-4 for Region 3 for the current licensed power level, and add a new TS Figure 3.9-5 for Region 3 for the SPU. The existing TS Figure 3.9-4 would be used for fuel that has exclusively been operated in reactor cores in the current licensed power level. The proposed TS Figure 3.9-5 would be used for fuel that has operated in at least 1 reactor core under SPU conditions. Two TS curves for Region 3 was determined by DNC to be appropriate in order to avoid unnecessary irradiated fuel movement. If a single most limiting curve was used for Region 3 fuel storage, the proposed SPU curve of allowable fuel enrichment versus burnup and decay time would be the required most conservative curve. Use of the SPU curve of allowed fuel, rather than the existing TS curve of allowed fuel, would then force a large number of fuel assemblies that are currently stored in Region 3, to be moved out of Region 3. This is unnecessary, since the fuel currently stored in Region 3 under the current licensed power level are still acceptable for storage in Region 3, provided they do not go back into the reactor for operation at the SPU power level.
- Accident Conditions – As described in WCAP-16721-NP, various accidents were analyzed for their effect on the spent fuel pool K-effective. Soluble boron is needed to mitigate certain accident conditions. The limiting accident condition, consistent with the current design and licensing basis, is the inadvertent placement or drop of a 5 weight percent fresh fuel assembly in a vacant Region 3 storage location, surrounded by other Region 3 storage locations filled with fuel of TS limiting allowed reactivity. The analysis for this storage region confirms that there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor (K_{eff}) will remain less than 0.95. This analysis credits soluble boron for the limiting accident condition. The amount of soluble boron needed per

WCAP-16721-NP is 402 ppm to mitigate the limiting accident event. This is far less than the current TS requirement of 800 ppm; therefore, no TS changes are needed.

In summary, the analysis provided in WCAP-16721-NP outlines the limits on soluble boron concentration, enrichment, burnup and decay times of the fuel that ensure that there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor (K_{eff}) of the MPS3 spent fuel pool will remain less than 0.95 under all conditions.

2.8.6.2.3 Conclusion

DNC concludes that the effects of the proposed SPU on the spent fuel rack criticality analyses have been accounted for by a complete criticality re-analysis of all fuel storage racks in the spent fuel pool and the results of these analyses are acceptable. DNC concludes that the spent fuel pool design will continue to ensure an acceptable degree of subcriticality following implementation of the proposed SPU. Based on this, DNC concludes that the spent fuel storage facilities will continue to meet the requirements of GDCs -4 and -62 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to spent fuel storage.

2.8.7 Additional Review Areas (Reactor Systems)

2.8.7.1 NSSS/BOP Pumps, Heat Exchangers, Valves, and Tanks

2.8.7.1.1 Regulatory Evaluation

NSSS/BOP systems support plant operation during normal operations and certain transient conditions. The DNC review of NSSS/BOP components focused on the effects of the proposed SPU on the various systems' components continued functionality, including the capability to provide heat sink capacity and withstand any adverse dynamic loads (e.g., water hammer, flow-induced vibration, thermal transients, maximum operating temperatures, and pressures).

NRC review standard RS-001 does not explicitly reference the SRP or other guidance documentation for licensing basis reviews regarding the equipment discussed in this section. RS-001 contains individual review sections, which specifically address major plant components (e.g., SG, RV, RCPs, pressurizer, CRDMs, etc.).

MPS3 Current Licensing Basis

Tables 2.8.7.1-1 through 2.8.7.1-4 list components, e.g., heat exchangers, pumps, tanks, valves, from the RCS, RHR system, CVCS (charging, letdown, regenerative functions), LPSI system, and HPSI system that are important to safety, which are not specifically addressed in individual sections. FSAR Sections 5.4.7, 5.4.8, 5.4.11, 5.4.12, 5.4.13, 6.3, and 9.3.4 provide descriptions of the components. In addition, FSAR Chapter 3 provides the details of the environmental activities and dynamic effects to which the SSCs important to safety are designed.

The components identified in Tables 2.8.7.1-1 through 2.8.7.1-4 are classified as QA Category I. They are designed in accordance with the codes and classifications defined in FSAR Section 3.2.5.

The MPS3 NSSS/BOP components were evaluated for plant license renewal. NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3," dated August 1, 2005, documents the results of that review. NUREG-1838 Sections 2.3B.1.3.1 and 3.1B are applicable to the PRT and RCS valves. NUREG-1838 Sections 2.3B.3.15 and 3.3B are applicable to the RCP Seal Standpipes and the CHS pumps, tanks, heat exchanges and valves. NUREG-1838 Sections 2.3B.2.3and 3.2B are applicable to the Safety Injection System (LPSI and HPSI) pumps, tanks and valves. NUREG-1838 Sections 2.3B.2.4 and 3.2B are applicable to the RHR System pumps, heat exchangers and valves.

2.8.7.1.2 Technical Evaluation

2.8.7.1.2.1 Introduction

The NSSS/BOP components for MPS3 were evaluated for the SPU. The equipment includes the NSSS/BOP heat exchangers, pumps, valves and tanks. The heat exchangers, pumps, valves, and tanks are listed in Tables 2.8.7.1-1 through 2.8.7.1-4 respectively. An evaluation was performed to determine the impact of the revised design conditions due to the SPU as compared to the original as supplied design conditions.

2.8.7.1.2.2 Description of Analyses and Evaluations

The system design parameters were compared to the SPU conditions. The design conditions included design temperature, and pressure. The NSSS/BOP technical documentation was then reviewed to establish the equipment original design conditions. The specified criteria again included design temperature, and pressure. These parameters were compared to those used in the system review for the SPU to determine if the design parameters continue to bound those for the SPU. System component design evaluations are contained in the applicable section.

NSSS/BOP Heat Exchangers and Tanks

The NSSS/BOP heat exchangers and tanks evaluated are listed in Tables 2.8.7.1-1 and 2.8.7.1-4, respectively. Based on the SPU conditions presented in Table 1-1, there was no impact on the NSSS/BOP heat exchangers and tanks as a result of the SPU. The operating temperature and pressure ranges for these components remained bounded by the original design parameters. The SPU design transients are bounded by the original design transients for the NSSS/BOP components. As a result, the heat exchangers and tanks are not adversely impacted by the SPU.

NSSS/BOP Pumps

The NSSS/BOP pumps evaluated are listed in Table 2.8.7.1-2. Based on the SPU conditions presented in Table 1-1, there was no adverse impact on the NSSS/BOP pumps. The operating temperature and pressure ranges for these pumps remained bounded by the original design parameters. The SPU design transients are bounded by the original design transients for the NSSS/BOP components. Based on this, the pumps are not adversely impacted by the SPU.

NSSS/BOP Valves

The NSSS/BOP valves evaluated are listed in Table 2.8.7.1-3. Based on the SPU conditions presented in Table 1-1, there was no adverse impact on the NSSS/BOP valves. The operating temperature and pressure ranges for the valves remained bounded by the original design parameters. In addition, the design transients for the SPU NSSS/BOP components are bounded by original design transients. As a result, the valves are not adversely impacted by the SPU.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application for the NSSS/BOP components. SPU activities do not add any new components, nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating the NSSS/BOP components at SPU conditions does not add any new or previously unevaluated materials. NSSS/BOP components internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.8.7.1.2.3 Results

The revised design conditions have been evaluated with respect to the impact on NSSS/BOP heat exchangers, pumps, valves, and tanks as defined in Tables 2.8.7.1-1 through 2.8.7.1-4. Based on SPU conditions defined in Table 1-1 and Section 2.2.6, and the results of this review, the MPS3 NSSS/BOP components affected by the SPU Program continues to meet the original design requirements.

2.8.7.1.3 Conclusion

DNC has reviewed the assessment of the effects of the SPU on the NSSS/BOP components and concludes that the evaluation has adequately accounted for the effects of changes in plant conditions on the design of the NSSS/BOP components. DNC concludes that the NSSS/BOP components will maintain their ability to perform their required function. DNC further concludes that the NSSS/BOP components will continue to meet the MPS3 current licensing basis requirements. Therefore, DNC finds the SPU acceptable with respect to the NSSS/BOP components.

Table 2.8.7.1-1
MPS3 NSSS/BOP Heat Exchangers

Component Name	MPS3 Tag Number	Reference MPS3 FSAR Figure No.
Letdown Chiller HX	3CHS*E6	9.3-8 SH.-2
Moderating HX	3CHS*E5	9.3-8 SH.-2
Seal Water HX	3CHS*E4	9.3-8 SH.-1
Regenerative HX	3CHS*E1	9.3-8 SH.-1
Excess Letdown HX	3CHS*E3	9.3-7 SH.- 1(A)
Letdown Reheat HX	3CHS*E7	9.3-8 SH.-2
Letdown HX	3CHS*E2	9.3-8 SH.-1
Residual HX	3RHS*E1A, 1B	5.4-5 SH.-1

Table 2.8.7.1-2
MPS3 NSSS/BOP Pumps

Component Name	MPS3 Tag Number	Reference FSAR Figure No.
Boric Acid Transfer Pump	3CHS*P2A, 2B	9.3-8 SH.-3
Centrifugal Charging Pumps	3CHS*P3A, 3B and 3C	9.3-8 SH.-1
Chiller Pump	3CHS*P1A and 1B	9.3-8 SH.-2
Hydrotest Pump	3 SIH*P3	6.3-2 SH.-1
RHR Pump	3RHS*P1A,1B	5.4-5 SH.-1
Safety Injection Pump	3SIH*P1A,1B	6.3-2 SH.-2

Table 2.8.7.1-3
MPS3 Class 1 Valves

Loop Stop Valve System		
MPS3 Tag Number	**Alternate ID**	**Reference FSAR Figure No.**
M33RCS*MV8001A	3RCS*V2	5.1-1 SH.-1
M33RCS*MV8001B	3RCS*V4	5.1-1 SH.-4
M33RCS*MV8001C	3RCS*V6	5.1-1 SH.-2
M33RCS*MV8001D	3RCS*V8	5.1-1 SH.-5
M33RCS*MV8002A	3RCS*V1	5.1-1 SH.-1
M33RCS*MV8002B	3RCS*V3	5.1-1 SH.-4
M33RCS*MV8002C	3RCS*V5	5.1-1 SH.-2
M33RCS*MV8002D	3RCS*V7	5.1-1 SH.-5
M33RCS*MV8003A	3RCS*V9	5.1-1 SH.-1
M33RCS*MV8003B	3RCS*V53	5.1-1 SH.-4
M33RCS*MV8003C	3RCS*V87	5.1-1 SH.-2
M33RCS*MV8003D	3RCS*V128	5.1-1 SH.-5
M33RCS*V050	3RCS*V50	5.1-1 SH.-1
M33RCS*V086	3RCS*V86	5.1-1 SH.-4
M33RCS*V117	3RCS*V117	5.1-1 SH.-2
M33RCS*V156	3RCS*V156	5.1-1 SH.-5
M33RCS*V013	3RCS*V13	5.1-1 SH.-1
M33RCS*V057	3RCS*V57	5.1-1 SH.-4
M33RCS*V091	3RCS*V91	5.1-1 SH.-2
M33RCS*V132	3RCS*V132	5.1-1 SH.-5
M33RCS*V011	3RCS*V11	5.1-1 SH.-1
M33RCS*V055	3RCS*V55	5.1-1 SH.-4
M33RCS*V089	3RCS*V89	5.1-1 SH.-2
M33RCS*V130	3RCS*V130	5.1-1 SH.-5
M33RCS*V012	3RCS*V12	5.1-1 SH.-1
M33RCS*V056	3RCS*V56	5.1-1 SH.-4
M33RCS*V090	3RCS*V90	5.1-1 SH.-2
M33RCS*V131	3RCS*V131	5.1-1 SH.-5
M33RCS*V010	3RCS*V10	5.1-1 SH.-1
M33RCS*V054	3RCS*V54	5.1-1 SH.-4
M33RCS*V088	3RCS*V88	5.1-1 SH.-2
M33RCS*V129	3RCS*V129	5.1-1 SH.-5

Table 2.8.7.1-3
MPS3 Class 1 Valves (continued)

Pressurizer Valves		
MPS3 Tag Number	**Alternate ID**	**Reference FSAR Figure No.**
M33RCS*SV8010A	3RCS*V171	5.1-1 SH.-3
M33RCS*SV8010B	3RCS*V172	5.1-1 SH.-3
M33RCS*SV8010C	3RCS*V173	5.1-1 SH.-3
M33RCS*PCV455A	3RCS*V168	5.1-1 SH.-3
M33RCS*PCV455B	3RCS*V14	5.1-1 SH.-3
M33RCS*PCV455C	3RCS*V58	5.1-1 SH.-3
M33RCS*PCV456	3RCS*V170	5.1-1 SH.-3
Miscellaneous		
MPS3 Tag Number	**Alternate ID**	**Reference FSAR Figure No.**
M33RCS*AV8036A	3RCS*V23	5.1-1 SH.-1
M33RCS*AV8036B	3RCS*V67	5.1-1 SH.-1
M33RCS*AV8036C	3RCS*V100	5.1-1 SH.-2
M33RCS*AV8036D	3RCS*V141	5.1-1 SH.-5
M33RCS*AV8037A	3RCS*V202	5.1-1 SH.-6
M33RCS*AV8037B	3RCS*V205	5.1-1 SH.-6
M33RCS*AV8037C	3RCS*V208	5.1-1 SH.-6
M33RCS*AV8037D	3RCS*V211	5.1-1 SH.-6
M33RCS*SV8095A	3RCS*V962	5.1-1 SH.-6
M33RCS*SV8095B	3RCS*V963	5.1-1 SH.-6
M33RCS*SV8096A	3RCS*V965	5.1-1 SH.-6
M33RCS*SV8096B	3RCS*V964	5.1-1 SH.-6
M33RCS*MV8000A	3RCS*V167	5.1-1 SH.-3
M33RCS*MV8000B	3RCS*V169	5.1-1 SH.-3
M33RCS*V024	N/A	5.1-1 SH.-1
M33RCS*V068	3RCS*V68	5.1-1 SH.-1
M33RCS*V099	3RCS*V99	5.1-1 SH.-2
M33RCS*V140	3RCS*V140	5.1-1 SH.-5
M33RCS*V201	3RCS*V201	5.1-1 SH.-6
M33RCS*V204	3RCS*V204	5.1-1 SH.-6
M33RCS*V207	3RCS*V207	5.1-1 SH.-3
M33RCS*V210	3RCS*V210	5.1-1 SH.-6

Table 2.8.7.1-3
MPS3 Class 1 Valves (continued)

MPS3 Tag Number	Alternate ID	Reference FSAR Figure No.
M33RCS*V203	3RCS*V203	5.1-1 SH.-6
M33RCS*V206	3RCS*V206	5.1-1 SH.-3
M33RCS*V209	3RCS*V209	5.1-1 SH.-6
M33RCS*V212	3RCS*V212	5.1-1 SH.-6
M33RCS*V033	3RCS*V33	5.1-1 SH.-1
M33RCS*V034	3RCS*V34	5.1-1 SH.-1
M33RCS*V153	3RCS*V153	5.1-1 SH.-1
M33RCS*V956	3RCS*V956	5.1-1 SH.-1
M33RCS*V108	3RCS*V108	5.1-1 SH.-2
M33RCS*AV8145	3RCS*V174	5.1-1 SH.-3
M33RCS*AV8153	3RCS*V213	5.1-1 SH.-6
M33RCS*V198	3RCS*V198	5.1-1 SH.-6
M33RCS*V175	3RCS*V175	5.1-1 SH.-3
M33RCS*V032	3RCS*V32	5.1-1 SH.-1
M33RCS*V031	3RCS*V31	5.1-1 SH.-1
M33RCS*V148	3RCS*V148	5.1-1 SH.-5
M33RCS*V147	3RCS*V147	5.1-1 SH.-5
M33RHS*MV8701A	3RHS*V997	5.4-5 SH.-1
M33RHS*MV8701C	3RHS*V999	5.4-5 SH.-1
M33RHS*MV8702B	3RHS*V996	5.4-5 SH.-1
M33RHS*MV8702C	3RHS*V998	5.4-5 SH.-1
M33RCS*V981	3RCS*V981	5.1-1 SH.-2
M33RCS*V980	3RCS*V980	5.1-1 SH.-2
M33SIH*V006	3SIH*V6	6.3-2 SH.-1
M33SIH*V007	3SIH*V7	6.3-2 SH.-1
M33SIH*V008	3SIH*V8	6.3-2 SH.-1
M33SIH*V009	3SIH*V9	6.3-2 SH.-1
M33SIH*V005	3SIH*V5	6.3-2 SH.-1
M33SIL*V026	3SIL*V26	6.3-2 SH.-1
M33SIL*V028	3SIL*V28	6.3-2 SH.-1
M33SIL*V987	3SIL*V987	5.4-5 SH.-2
M33SIL*V986	3SIL*V986	5.4-5 SH.-2
M33SIL*V985	3SIL*V985	5.4-5 SH.-2
M33SIL*V984	3SIL*V984	5.4-5 SH.-2

Table 2.8.7.1-3
MPS3 Class 1 Valves (continued)

MPS3 Tag Number	Alternate ID	Reference FSAR Figure No.
M33RCS*V029	3RCS*V29	5.1-1 SH.-1
M33RCS*V070	3RCS*V70	5.1-1 SH.-4
M33RCS*V106	3RCS*V106	5.1-1 SH.-2
M33RCS*V145	3RCS*V145	5.1-1 SH.-5
M33SIH*V110	3SIH*V110	6.3-2 SH.-2
M33SIL*V027	3SIL*V27	5.4-5 SH.-1
M33SIH*V112	3SIH*V112	6.3-2 SH.-2
M33SIL*V029	3SIL*V29	5.4-5 SH.-1
M33RCS*V030	3RCS*V30	5.1-1 SH.-2
M33RCS*V071	3RCS*V71	5.1-1 SH.-4
M33RCS*V107	3RCS*V107	5.1-1 SH.-2
M33RCS*V146	3RCS*V146	5.1-1 SH.-5
M33RCS*V026	3RCS*V26	5.1-1 SH.-1
M33RCS*V069	3RCS*V69	5.1-1 SH.-4
M33RCS*V102	3RCS*V102	5.1-1 SH.-2
M33RCS*V142	3RCS*V142	5.1-1 SH.-5
M33SIL*V015	3SIL*V15	5.4-5 SH.-2
M33SIL*V017	3SIL*V17	5.4-5 SH.-2
M33SIL*V019	3SIL*V19	5.4-5 SH.-2
M33SIL*V021	3SIL*V21	5.4-5 SH.-2
M33RCS*LCV459	3RCS*V110	5.1-1 SH.-2
M33RCS*LCV460	3RCS*V109	5.1-1 SH.-2

Table 2.8.7.1-4
MPS3 NSSS/BOP Tanks

Component Name	MPS3 Tag Number	Reference FSAR Figure No.
Boric Acid Batch Tank	3CHS*TK6	9.3-8 SH.-3
Chemical Mixing Tank	3CHS*TK4	9.3-8 SH.-3
Chiller Surge Tank	3CHS*TK3	9.3-8 SH.-2
Pressurizer Relief Tank	3RCS*TK2	5.1-1 SH.-6
RCP Seal Standpipe	3CHS*TK7A, 7B, 7C and 7D	9.3-7 SH.-1(A)
Accumulator Tank	3SIL*TK 1A, 1B, 1C, and 1D	5.4-5 SH.-2
Volume Control Tank	3CHS*TK2	9.3-8 SH.-1

2.8.7.2 Natural Circulation Cooldown

2.8.7.2.1 Regulatory Evaluation

NRC review standard RS-001 Rev. 0 does not explicitly call out SRPs or other guidance documentation for current or post-uprate license basis reviews for natural circulation cooldown.

However, NRC Branch Technical Position (BTP) RSB 5-1, “Design Requirements of the Residual Heat Removal (RHR) System”, requires that test programs for PWRs include tests with supporting analyses to: (1) confirm that adequate mixing of borated water added prior to or during cooldown can be achieved under natural circulation conditions and permit estimation of the times required to achieve such mixing, and (2) confirm that the cooldown under natural circulation conditions can be achieved within the limits specified in the EOPs. In addition, the plant is to be designed so that the reactor can be taken from normal operating conditions to cold shutdown using only safety-grade systems. A comparison of performance to that of previously tested plants of similar design may be substituted for these tests.

MPS3 Current Licensing Basis

In Section 5.4.7.5 of NUREG-1031, “Safety Evaluation Report Related to the Operation of Millstone Nuclear Power Station, Unit No. 3,” the NRC indicated that verification of adequate mixing of borated water added to the reactor coolant system under natural circulation conditions and confirmation of natural circulation cooldown ability could be accomplished either by reference to the results of the tests from a plant similar in design or actual testing to be conducted at MPS3. On March 28 and 29, 1985, a boron mixing and cooldown test was performed at Diablo Canyon Unit 1. This test (results are documented in WCAP-11086, March 1986) demonstrated that the plant could be safely taken to cold shutdown under natural circulation conditions. In a letter dated November 6, 1987 and supplemented by a letter dated August 3, 1988, a Natural Circulation System Comparison Report was submitted for MPS3. The evaluation included in this report demonstrates that MPS3 capabilities are comparable to those of Diablo Canyon Unit 1.

In a letter dated October 18, 1988 the NRC accepted NNECO’s justification that the results of the Diablo Canyon Unit 1 natural circulation cooldown tests applied to MPS3 and were an acceptable alternative to showing that MPS3 meets the requirements of BTP RSB 5-1. This letter indicates:

- MPS3 is classified as a Class 2 plant with regard to the implementation of BTP RSB 5-1
- The natural circulation/boron mixing/cooldown test performed at Diablo Canyon Unit 1 on March 28-29, 1985 meets the intent of BTP RSB 5-1 for a Class 2 plant
- The NRC concluded that the results of the Diablo Canyon Unit 1 natural circulation tests are applicable to MPS3 and that they comply with the requirements of BTP RSB 5-1

In addition, Dominion EOP 35 ES-02 Rev. 014 guidance (no accident in progress) follows the Westinghouse Owners Group Emergency Response Guidelines (WOG ERGs, Rev. 1C) for natural circulation cooldown. EOP 35 ES-03 Rev. 10 and EOP 35 ES-04 Rev. 11 address natural circulation cooldown with steam void conditions. Operator training covers a number of EOPs which address natural circulation.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” DATED August 1, 2005, defines the scope of license renewal. Natural Circulation Cooldown capability was not within the scope of License Renewal.

2.8.7.2.2 Technical Evaluation

2.8.7.2.2.1 Introduction

This section summarizes the Diablo Canyon Unit 1 natural circulation comparison to support the MPS3 Stretch Power Uprate (SPU) Program.

Natural circulation is a heat removal process whereby reactor coolant system (RCS) flow is driven by temperature and density differences in the RCS fluid between the core and steam generators. Heat transferred to fluid in the core causes an increase in temperature and a decrease in density of the fluid. Since this fluid is warmer than the fluid in the steam generators, which are higher in elevation than the core exit, and warmer fluid rises, it is driven into the steam generators. There heat is removed by the cooler secondary water which lowers the temperature and increases the density of the RCS fluid. On the cold leg side of the steam generators, this higher density results in a force pushing the water out of the steam generators into the RCP suction leg. The combination of core heat addition and steam generator heat removal will, therefore, cause continuous flow to develop through the RCS and ensure enough heat removal to adequately cool the core.

Natural circulation cooling depends on the geometric configuration of the plant and on the capabilities of plant systems to provide support for the cooling process. The natural circulation mass flow is directly proportional (using a “1/3” exponent) to decay heat level and thermal driving head and indirectly proportional (using a “1/3” exponent) to loop hydraulic resistance. The effects of thermal driving head and loop hydraulic resistance were specifically evaluated for the MPS3 configuration for the SPU. The effect of increasing power will be to increase the natural circulation flow above that which would occur at the same time after shutdown for the MPS3 plant prior to the SPU. The Diablo Canyon Unit 1 natural circulation test demonstrated capability to initiate and maintain natural circulation flow.

2.8.7.2.2.2 Description of Analyses and Evaluations

To demonstrate capability for natural circulation decay heat removal, many utilities reference the Diablo Canyon Unit 1 natural circulation cooldown test performed in 1985 and provide justification that this test reflects the capability of their plant by comparing relevant parameters. These parameters include hydraulic resistances, and natural circulation driving heads. For this evaluation, the effects of the SPU at varying levels of Steam Generator Tube Plugging (SGTP) on the hydraulic resistance, flow ratio per loop, and thermal driving head are compared to Diablo Canyon Unit 1.

Impact on Renewed Plant Operating License Evaluations and License Renewal

MPS3 has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal Application for the impact on Natural Circulation Cooldown.

Natural Circulation Cooldown capability is inherent in the design of the plant. There are no aspects of that capability that are age-related such that the capability would be degraded by operation beyond a 40 year life. Therefore, there is no impact on the evaluations performed for License Renewal and they remain valid for the SPU conditions. In addition, the capability for natural circulation cooldown is not limited by the original license period and can be relied upon to provide core cooling throughout the licensed life of the plant.

2.8.7.2.2.3 Results

Natural Circulation

The Diablo Canyon Unit 1 natural circulation test evaluation verified that RCS natural circulation flow could be established, thereby permitting boron mixing and RCS cooldown/depressurization to RHR system initiation conditions. This test had no specific acceptance criteria and it was evaluated based on the results of boron mixing and cooldown/depressurization phases of the natural circulation cooldown test.

The Diablo Canyon Unit 1 test results indicated that natural circulation flow rates were adequate to ensure that core decay heat removal, boron mixing and plant cooldown/depressurization were maintained throughout the test. The response of the RCS temperatures indicated stable natural circulation conditions throughout the test.

MPS3 and Diablo Canyon Unit 1 were compared as discussed in the August 3, 1988 letter from NNECO to the NRC to ascertain any differences between the two plants that could potentially affect natural circulation flow. An additional evaluation was performed for the SPU to show that the conclusions of the original comparison are still valid. The general configuration of the piping and components in each reactor coolant loop is the same in both MPS3 and Diablo Canyon Unit 1. The elevation head represented by these components and the system piping is similar in both plants. Steam generator units were also compared to ascertain any variation that could affect natural circulation capability by changing the effective elevation of the heat sink of the hydraulic resistance seen by the primary coolant. The longer tube bundle at Diablo Canyon Unit 1 would result in 5-10 percent higher driving head when compared to MPS3. However, there are no significant differences in the design of the steam generators in the two plants that would adversely affect the natural circulation characteristics.

To compare the natural circulation capabilities of MPS3 and Diablo Canyon Unit 1, the hydraulic resistance coefficients for the MPS3 SPU configuration were compared to the hydraulic resistance coefficients for Diablo Canyon Unit 1 at the time of the 1985 natural circulation test. The coefficients were generated on a per loop basis. The hydraulic resistance coefficients tabulated in Table 2.8.7.2-1 are applicable to normal flow conditions. Although the hydraulic resistance coefficients would increase slightly for natural circulation conditions, the ratio of the total hydraulic flow coefficients remains applicable for natural circulation conditions since the individual hydraulic resistance coefficients for the two comparable plants would be affected in a similar manner. Therefore, the flow ratio per loop as reported below is expected to be valid for both normal flow and natural circulation conditions.

The general arrangement of the reactor core and internals is the same in Diablo Canyon Unit 1 and MPS3. The Diablo Canyon Unit 1 vessel inlet nozzle radius is significantly smaller than that of MPS3, as reflected by the higher coefficient for Diablo Canyon Unit 1. The installed core for Diablo Canyon Unit 1 and the core considered in the original natural circulation evaluation for MPS3 contained Westinghouse standard fuel and had fuel assembly thimble plugs installed. The SPU natural circulation evaluation for MPS3 considers a core of RFA fuel with fuel assembly thimble plugs removed. The flow losses are otherwise very similar for the two plants. The coefficients represent the resistance seen by the flow in one loop, excluding the resistance through the reactor coolant pump. The RCP flow resistances for the two plants are on the same order of magnitude as the total hydraulic flow coefficients reported above are comparable since the RCP impeller designs for the Diablo Canyon Unit 1 and MPS3 pumps are nearly identical. Accordingly, the flow ratio per loop as reported above would remain very close to unity when considering RCP flow resistance.

If the effect of the 5-10 percent increased natural circulation driving head for Diablo Canyon Unit 1 is taken into account, the flow ratio would change to approximately 0.96 (10 percent SGTP) – 0.98 (0 percent SGTP). When the uprated licensed core power for MPS3 (3650 MWt) versus the licensed core power of PGE (3338 MWt) is considered in comparing the ratio of mass flows, MPS3 will have approximately 3 percent more flow than Diablo Canyon Unit 1 for the same time after Shutdown (Percent Decay Heat). The significant parameters governing natural circulation are hydraulic flow resistance and thermal driving head. Since the proposed SPU will not alter these parameters, changes in the natural circulation loop flow for MPS3 due to SPU are as discussed above and the ability to establish and maintain natural circulation cooldown as described in the 1987 comparison of Diablo Canyon Unit 1 and MPS3 remains valid.

Boron Mixing

The Diablo Canyon Unit 1 boron mixing test evaluation demonstrated adequate mixing under natural circulation conditions when highly borated water at low temperatures and low flow rates (relative to RCS temperature and flow rate) was injected into the RCS. DNC also evaluated the time delay associated with boron mixing under these conditions.

The acceptance criterion for this phase of the Diablo Canyon Unit 1 test was that RCS hot legs (loops 1 and 4) indicate that the active portions of the RCS were borated such that the boron concentration had increased by 250 ppm or more.

Boron injection was conducted at the Diablo Canyon Unit 1 test using the 20,000 ppm boron solution contained in the boron injection tank (BIT). The BIT's contents were flushed into the RCS and within 12 minutes, natural circulation had provided adequate mixing to increase the boron concentration in the RCS by 340 ppm.

Due to configuration differences from Diablo Canyon Unit 1, at MPS3, boron would be injected into the RCS from the BATs (with a Technical Specification requirement for boric acid solution at 6600 ppm boron) through the RCP seals and the normal charging line, if available. Since the BAT boron concentration (6600 ppm) at MPS3 is less than that used for the successful Diablo Canyon Unit 1 test, the addition of a larger quantity of borated water over a longer time period is required for MPS3 to achieve a similar change in boron concentration. However, because natural circulation flow at MPS3 is expected to be larger than the flow obtained at Diablo Canyon Unit 1, adequate mixing of boron would also be provided for MPS3. In addition, a safety grade backup means of boron injection is provided by the SIS flow path.

Westinghouse Calculation CN-FSE-06-54 confirms that the BAST's are adequately sized for SGCS and computes several boration times including "boration time to cold shutdown concentrations using BAT and max letdown". For Safety Grade Cold Shutdown (head vent letdown), the longest boration period is computed and is confirmed to be less than 6-hours. Page 31 of Westinghouse Calculation CN-FSE-06-54 shows Boric Acid Storage Tank (BAST) boration time (assuming the maximum letdown rate) in the 2.5-3.5 hour range. Therefore, Westinghouse Calculation CN-FSE-06-54 provides an adequate technical bases for concluding that the boration phase will be between 2 and 6 hours in duration.

To support the MPS3 SPU, a boron mixing evaluation was performed for MPS3 to show that sufficient natural circulation flow exists to adequately mix the boron that is added to the RCS. Since no major plant systems have changed to adversely affect cooldown and depressurization to RHR initiation conditions since the previous natural circulation evaluation (as discussed in the August 3, 1988 letter from NNECO to the NRC), the same equipment is available for boration. CREARE test report NP-2312 suggests a very high degree of mixing for a condition in which the loop flow is 10 times greater than the added liquid flow. The boron mixing evaluation compared charging flow with calculated natural circulation loop flow to determine that the loop flow was more than 10 times the charging flow. Since the ratio of natural circulation flow to charging flow exceeds 10, boron mixing will be adequate.

Reactor Coolant System Cooldown

The cooldown portion of the test at Diablo Canyon Unit 1 demonstrated the capability to cooldown the RCS to RHR system initiating condition at approximately 25°F/hour using all four steam generators for natural circulation. The RHR system was then used to cool the RCS to cold shutdown conditions. Plant cooldown was controlled within Technical Specification limits. All active portions of the RCS remained within 100°F of the average core exit temperature. Also, both the steam generators and reactor vessel upper head were cooled to below 450°F when the core exit temperature was 350°F.

The cooldown limits given in the Westinghouse Owners Group Emergency Response Guidelines and background document for natural circulation cooldown are not changed by the uprate. These cooldown limits are based on analyses performed for the development of the ERGs. These analyses assumed either a TBhotB upper head region or a TBcoldB upper head region. Since the Millstone Unit 3 reactor vessel has the upper head at TBcoldB and since this condition was not changed by the uprate, the same cooldown limits apply for natural circulation cooldown procedures before and after the uprate (i.e., 50°F/hr limit given CRDM cooling unavailability and maintenance of 100°F sub-cooling margin).

For MPS3, cooldown capability is similar to Diablo Canyon Unit 1 due to similarities in the design of the RCS, CVCS, AFW, main steam and RHR systems. The upper head volume for MPS3 is higher than that of Diablo Canyon Unit 1. However, the spray nozzle flow area for MPS3 is significantly higher. The upper head region for MPS3 is expected to cool at a rate comparable to or exceeding that of Diablo Canyon Unit 1. RCS cooldown at a rate up to 50°F/hour would be permitted for MPS3 because the upper head volume is maintained at TBcoldB. A 50°F/hour cooldown rate is permitted if the CRDM fans are not operating. Initial plant cooldown is accomplished via steam release from the main steam system. After RHR system initiation, the RHR system is used to cool the plant to cold shutdown temperatures.

Sufficient auxiliary feedwater has been shown to be available to Diablo Canyon to perform a natural circulation cooldown to cold shutdown conditions. The Dominion SGCS analysis (Section 2.8.4.4, Residual Heat Removal System) confirms that there is adequate DWST inventory to support a natural circulation cooldown to cold shutdown at MPS3.

Reactor Coolant System Depressurization

The depressurization portion of the test at Diablo Canyon Unit 1 demonstrated the capability to control pressure in the RCS under natural circulation conditions. Pressure control capability included the ability to maintain adequate RCS pressure without operating the pressurizer heaters and the ability to significantly reduce RCS pressure when needed to initiate RHR system operation. Three methods of reducing pressure were demonstrated. During the RCS cooldown, pressurizer pressure exhibited a downward trend due to ambient heat losses from the pressurizer. This was followed by operator initiated RCS depressurization using the auxiliary spray. For auxiliary spray to be effective, the charging lines to the RCS loops must be isolated. Finally, depressurization was completed using a pressurizer PORV. Each method was determined to be effective in reducing RCS pressure.

For MPS3, pressure control and depressurization capability is similar to Diablo Canyon Unit 1 due to similarities in the design of the RCS and CVCS. Ambient heat losses would gradually reduce RCS pressure. System and component evaluations at the SPU conditions have confirmed that the pressurizer PORVs continue to have the capability to control and reduce RCS pressure when required. Additional evaluations have shown that the pressurizer auxiliary spray can also control and reduce RCS pressure when needed. At MPS3, two pressurizer heater backup units are powered from an emergency power source and are available during a loss of offsite power. At MPS3, the PORVs are safety grade, are powered from an emergency power source and are available during a loss of offsite power. Therefore, the pressurizer PORVs and the auxiliary spray will remain effective in controlling RCS pressure and depressurizing the RCS when needed to permit RHR system initiation.

Summary

The Diablo Canyon Unit 1 Natural Circulation/Boron Mixing/Cooldown Test demonstrated that the plant can safely be taken to cold shutdown under natural circulation conditions.

In order to apply the test results to MPS3, a general comparison of the plant systems and equipment that affect natural circulation, boron mixing, cooldown and depressurization capabilities has been made between the MPS3 and Diablo Canyon Unit 1 plants in the previous MPS3 evaluation. Current plant conditions and capabilities at the SPU conditions have been evaluated using methods similar to those used in the original MPS3 natural circulation cooldown comparison as discussed in the August 3, 1988 letter from NNECO to the NRC. The conclusions of the original MPS3 natural circulation cooldown comparison are still valid. The evaluation demonstrates that the MPS3 capabilities are comparable to those of Diablo Canyon Unit 1. Therefore it is concluded that MPS3 at SPU conditions meets the testing comparison requirements of Branch Technical Position RSB 5-1, Design Requirements for Decay Heat Removal Systems.

2.8.7.2.3 Conclusion

MPS3 has reviewed the assessment of the effects of the proposed SPU on natural circulation cooldown and concludes that the evaluation has adequately accounted for the effects of changes in plant conditions. The MPS3 staff concludes that MPS3 maintains the ability to perform a natural circulation cooldown following a trip from full power to RHR cut-in conditions. Therefore, the MPS3 staff finds the proposed SPU acceptable with respect to the systems used for natural circulation cooldown.

Table 2.8.7.2-1
Diablo Canyon Unit 1 versus MPS3

Hydraulic Resistance Coefficients [ft/(gpm)^2] for Normal Flow Conditions			
	Diablo Canyon Unit 1 [ft/(gpm)^2]	**MPS3 SGTP = 0%**	**MPS3 SGTP = 10%**
Reactor Core and Internals	129.0E-10	125.6E-10	125.6E-10
Reactor Nozzles	36.1E-10	26.62E-10	26.62E-10
Reactor Coolant Loop Piping	20.9E-10	24.00E-10	24.00E-10
Steam Generator	112.0E-10	118.0E-10	141.46E-10
Total Hydraulic Flow Resistance Coefficient (without RCPs)	298.0E-10	294.2E-10	317.6E-10
$Flow\ Ratio = \left[\frac{HFC_{tot}\ \ for\ Diablo\ Canyon\ \ Unit\ \ 1}{HFC_{tot}\ \ for\ MPS3}\right]^{1/3} = \left[\frac{2.980x10^{-8}}{2.942x10^{-8}}\right]^{1/3} = 1.0043$			
Note: Flow ratio is defined as the ratio of the Millstone mass flow rate to the Diablo Canyon mass flow rate. The ratio is for hydraulic resistance difference impact only.			

2.8.7.3 Mid-Loop Operation

2.8.7.3.1 Regulatory Evaluation

For loss of RHR at mid-loop or reduced inventory conditions, RS-001, Rev. 0, does not explicitly references the SRP or other guidance documentation. In addition, there are no specific NRC acceptance criteria within NRC regulations for operations at mid-loop or reduced inventory conditions.

NRC Generic Letter (GL) 88-17, Loss of Decay Heat Removal, identified actions to be taken to preclude loss of decay heat removal during non-power operations. These actions included operator training and the development of procedures and hardware modifications as necessary to prevent the loss of decay heat removal during reduced reactor coolant inventory operations, to mitigate accidents before they progress to core damage, and to control radioactive material if a core damage accident should occur. Procedures and administrative controls were required to address reduced inventory operations and ensure that all hot legs were not blocked by nozzle dams, or closed loop stop valves, unless a vent path was provided that is large enough to prevent pressurization and loss of water from the reactor vessel. Instrumentation was required to provide continuous core exit temperature and reactor water level indication. Sufficient equipment was required to be maintained in an operable or available status so as to mitigate the loss of the RHR cooling or loss of RCS inventory should such an event occur during mid-loop or reduced inventory conditions.

MPS3 Current Licensing Basis

In a letter dated October 17, 1988, the NRC requested all holders of operating licenses to respond to recommended expeditious actions and programmed enhancements identified in GL 88-17. The MPS3 response to the GL 88-17 recommended expeditious actions was provided in a letter dated December 23, 1988. In a letter dated July 12, 1989, the NRC concluded that MPS3 had adequately met the required expeditious actions of GL 88-17. Additional information was submitted to the NRC regarding the MPS3 level indication system that is utilized to monitor the RCS water level during a reduced inventory condition, on April 4, 1990, and April 28, 1995.

The MPS3 response to the GL 88-17 recommended programmed enhancements was provided in a letter dated January 31, 1989. In a letter dated March 25, 1991, the NRC concluded that the programmed enhancements had been adequately implemented.

In a letter to the NRC dated April 21, 1993, Millstone informed the NRC of progress being made in the area of shutdown risk management and plans to address NUMARC 91-06, Guidelines for Industry Actions to Assess Shutdown Management. NUMARC 91-06 included guidelines regarding loss of decay heat removal. A self-assessment was conducted for MPS3 and changes were implemented to address NUMARC 91-06.

NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, defines the scope of license renewal. The programmatic commitments regarding GL 88-17 and the methodology for complying with the guidelines of NUMARC 91-06 for loss of decay heat removal were not within the scope of license renewal.

2.8.7.3.2 Technical Evaluation

A technical evaluation was conducted to determine the impact that the proposed SPU conditions would have on the MPS3 Current Licensing Basis for meeting each of the GL 88-17 expeditious actions and programmed enhancements and the guidelines specified in NUMARC 91-06 for loss of decay heat removal. The results of the evaluation are summarized in Table 2.8.7.3-1.

As stated in Section 2.8.7.3.1, the loss of decay heat removal at mid-loop operating conditions were not within the scope of License Renewal. Therefore, there is no impact of the SPU on the conclusions reached in NUREG-1838 in support of the renewed operating license.

2.8.7.3.3 Conclusion

The SPU conditions: 1) have no impact on the existing instrumentation that is utilized to monitor the RCS level and RHR performance during mid-loop operation; 2) do not require any additional instrumentation to monitor reduced inventory operation; and 3) have no impact on the availability of water sources credited in the shutdown risk assessment.

Calculation 99-517-01034RE, Shutdown Risk Calculation for NUMARC 91-06, and Operating Procedure OP 3260A, Conduct of Outages, are reviewed and revised as necessary every cycle to reflect cycle specific information and configurations. Accordingly, the calculation and operating procedure will be revised and implemented to reflect the higher decay heat due to the SPU prior to entering reduced inventory operation for the applicable fuel cycle. The calculation and operating procedure will remain consistent with the requirements of GL 88-17 and guidelines of NUMARC 91-06.

2.8.7.3.4 References

1. Letter from Northeast Nuclear Energy Company to the NRC, Haddam Neck Plant, Millstone Nuclear Power Station, Unit Nos. 2 and 3, Loss of Decay Heat Removal, Generic Letter 88-17, dated December 23, 1988.

2. Letter from Northeast Nuclear Energy Company to the NRC, Haddam Neck Plant, Millstone Nuclear Power Station, Unit Nos. 2 and 3, Loss of Decay Heat Removal, Generic Letter 88-17 (TAC Nos. 69754 and 69755), dated January 31, 1989.

3. Letter from Northeast Nuclear Energy Company to the NRC, Millstone Nuclear Power Station, Unit No. 3, Generic Letter 88-17, Revised Response to Expeditious Action Item 4, (Program Enhancement Item 1) (TAC No. 69755), dated April 4, 1990.

4. Letter from Northeast Nuclear Energy Company to the NRC, Haddam Neck Plant, Millstone Nuclear Power Station Unit Nos. 1, 2, and 3, Shutdown Risk Management, dated April 21, 1993.

5. Letter from Northeast Nuclear Energy Company to the NRC, Millstone Nuclear Power Station, Unit No. 3, Generic Letter 88-17, Revised Response – Expeditious Action Item 4, dated April 28, 1995.

6. Letter from the NRC to All Holders of Operating Licenses or Construction Permits for Pressurized Water Reactors, Loss of Decay Heat Removal (Generic Letter 88-17) 10 CFR 50.54(f), dated, October 17, 1988.

7. Letter from NRC to the Northeast Nuclear Energy Company, Comments on the Northeast Nuclear Energy Company Response to Generic Letter 88-17 with Respect to Expeditious Actions for Loss of Decay Heat Removal for Millstone Nuclear Power Station Unit 3 (TAC No. 69755), dated May 23, 1989.

8. Letter from NRC to the Northeast Nuclear Energy Company, Millstone 3 Routine Inspection 50-423/89-08 (5/15/89 – 6/12/89), dated July 12, 1989.

9. Letter from NRC to the Northeast Nuclear Energy Company, Programmed Enhancements for Generic Letter 88-17, Loss of Decay Heat Removal" (TAC NO. 69755, Millstone Unit 3, dated October 26, 1990.

10. Letter from NRC to the Northeast Nuclear Energy Company, Inspection No. 50-423/91-02, dated March 25, 1991.

11. Northeast Utilities Self-Assessment of Shutdown Management (NUMARC 91-06) at Connecticut Yankee and Millstone Station, dated August 1992.

12. NUMARC 91-06, Guidelines for Industry Actions to Assess Shutdown Management, dated December 1991.

Table 2.8.7.3-1

Regulatory Actions/Industry Guidelines	SPU Analysis Against MPS3 Current Licensing Basis
NRC Generic Letter 88-17 Expeditious Actions	
Provide training prior to operating in a reduced inventory condition.	The current training program addressing RHR system operation and reduced inventory operation is unaffected by the SPU. No change is required.
Implement procedures and administrative controls that reasonably ensure that containment closure would be achieved prior to the time at which core uncovery could result from a loss of decay heat removal, coupled with an inability to initiate alternate cooling or addition of water to the RCS inventory.	OP 3260A, Conduct of Outages, provides specific instructions for meeting the requirements for Containment Closure. The procedure requires the capability to establish containment closure prior to core boiling. This procedure contains tables of time to core boiling for various shutdown conditions. It is reviewed and revised as necessary every cycle to reflect cycle specific information and configurations. Accordingly, the applicable tables in OP 3260A will need to be revised to reflect the increase in decay heat due to SPU.
Provide at least two independent, continuous temperature indications representative of the core exit conditions whenever the RCS is in a mid-loop condition and the reactor vessel head is located on top of the reactor vessel.	The number of temperature indications required is unaffected by SPU. No change is required.
Provide at least two independent, continuous RCS water level indications whenever the RCS is in a reduced inventory condition.	The number of water level indications required is unaffected by SPU. No change is required.
Implement procedures and administrative controls that generally avoid operations that deliberately or knowingly lead to perturbations to the RCS and/or systems that are necessary to maintain the RCS in a stable and controlled condition while the RCS is in a reduced inventory condition.	The RHR flow rate limit is established to avoid vortexing and air entrainment and is independent of power level. No change is required to the established RHR flow rate limit. Due to the increase in power level by SPU.

Table 2.8.7.3-1

Regulatory Actions/Industry Guidelines	SPU Analysis Against MPS3 Current Licensing Basis
NRC Generic Letter 88-17 Expeditious Actions (continued)	
Provide at least two available or operable means of adding inventory to the RCS that are in addition to pumps that are a part of the normal decay heat removal systems.	The water injection sources that can be credited for shutdown safety assessment are specified in Form OP 3260A-004, "Shutdown Safety Assessment Checklist." At least two sources are needed for a yellow condition and three sources are needed for a green condition. Because of the large capacities of these pumped sources, the increase in decay heat due to the SPU will not require a change in these criteria.
Implement procedures and administrative controls that reasonably ensure that all hot legs are not blocked simultaneously by nozzle dams unless a vent path is provided that is large enough to prevent pressurization of the upper plenum of the reactor vessel.	This item is not applicable to MPS3 since it is equipped with loop stop valves and does not use nozzle dams.
Implement procedures and administrative controls that reasonably ensure that all hot legs are not blocked simultaneously by closed loop stop valves unless: • A vent path is provided that is large enough to prevent pressurization of the upper plenum of the reactor vessel, or • The RCS configuration prevents reactor vessel water loss if reactor vessel pressurization should occur.	This requirement is unaffected by SPU. No changes are needed.
NRC Generic Letter 88-17 Programmed Enhancements	
Provide reliable indication of parameters that describe the state of the RCS and the performance of systems normally used to cool the RCS for both normal and accident conditions.	The adequacy of the instrumentation is unaffected by SPU. No changes are needed.

Table 2.8.7.3-1

Regulatory Actions/Industry Guidelines	SPU Analysis Against MPS3 Current Licensing Basis
Develop and implement procedures that cover reduced inventory operation and that provide an adequate basis for entry into a reduced inventory condition.	Procedure OP 3260A, "Conduct of Outages," contains tables of time to core boiling for various shutdown conditions. It is reviewed and revised as necessary every cycle to reflect cycle specific information and configurations. Accordingly, the applicable tables in OP 3260A will need to be revised to reflect the increase in decay heat due to SPU.
Assure that adequate operating, operable, and/or available equipment of high reliability is provided for cooling the RCS and for avoiding a loss of RCS cooling. Maintain sufficient existing equipment in an operable or available status so as to mitigate loss of Decay Heat Removal or loss of RCS inventory should they occur. Provide adequate equipment for personnel communications that involve activities related to the RCS or systems necessary to maintain the RCS in a stable and controlled condition.	The water injection sources that can be credited for shutdown safety assessment is specified in Form OP 3260A-004, "Shutdown Safety Assessment Checklist." At least two sources are needed for a yellow condition and three sources are needed for a green condition. Because of the large capacities of these pumped sources, the increase in decay heat due to the SPU will not require a change in these criteria.
Conduct analyses to supplement existing information and develop a basis for procedures, instrumentation installation and response, and equipment/NSSS interactions and response.	Calculation 99-517-01034RE, "Shutdown Risk Calculation for NUMARC 91-06," and Operating Procedure OP 3260A, "Conduct of Outages," are reviewed and revised as necessary every cycle to reflect cycle specific information and configurations. Accordingly, this calculation requires revision to reflect the higher decay heat impact on the time to boil calculations.
Appropriate changes to the Technical Specifications should be made.	Since there is no impact on the systems available to mitigate a loss of RHR, no changes to the Technical Specifications are required to address the impact of the SPU on the equipment required to be available for mitigation of a loss of RHR.

Table 2.8.7.3-1

Regulatory Actions/Industry Guidelines	SPU Analysis Against MPS3 Current Licensing Basis
NRC Generic Letter 88-17 Programmed Enhancements (continued)	
The expeditious actions for RCS perturbations should be re-examined and operations refined as necessary to reasonably minimize the likelihood of loss of Decay Heat Removal.	The SPU has no impact on the actions taken to limit the possibility of RCS perturbations at reduced inventory conditions. Thus, no change is required.
NUMARC 91-06 Guidelines	
A procedure should be established to address loss of the normal Decay Heat Removal capability during shutdown conditions.	Procedure OP 3260A, Conduct of Outages, contains tables of time to core boiling for various shutdown conditions. It is reviewed and revised as necessary every cycle to reflect cycle specific information and configurations. Accordingly, the applicable tables in OP 3260A will need to be revised to reflect the increase in decay heat due to SPU.
The technical basis used to develop the procedure should also be used as an input to determining and planning an adequate defense in depth of the decay heat removal function for the outage that is commensurate with plant conditions.	Calculation 99-517-01034RE, Shutdown Risk Calculation for NUMARC 91-06. It is reviewed and revised as necessary every cycle to reflect cycle specific information and configurations. Accordingly, it will be revised to reflect the higher decay heat impact on the time to boil calculations
Containment hatches and other penetrations that communicate with the containment atmosphere should either be closed or capable of being closed prior to core boiling following a loss of decay heat removal and should be addressed in procedures.	While the SPU will shorten the calculated times for the onset of core boiling following a loss of decay heat removal, the containment closure criterion will be maintained. Thus, the SPU will not require a change to this criterion.

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

2.9.1.1 Regulatory Evaluation

DNC reviewed the radioactive source term associated with the SPU to ensure the adequacy of the sources of radioactivity used by MPS3 as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes.

The DNC review included the parameters used to determine the: 1) concentration of each radionuclide in the reactor coolant; 2) fraction of fission product activity released to the reactor coolant; 3) concentrations of all radionuclides other than fission products in the reactor coolant; 4) leakage rates and associated fluid activity of all potentially radioactive water and steam systems; and 5) potential sources of radioactive materials in effluents that are not considered in the FSAR, related to liquid waste management systems and gaseous waste management systems.

The acceptance criteria for source terms are based on:

1. 10 CFR 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas;

2. 10 CFR 50, Appendix I, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the “as low as is reasonably achievable” criterion; and

3. GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

Specific review criteria are contained in SRP Section 11.1, and guidance provided in Matrix 9 of RS-001.

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, “Standard Review Plant for the Review of Safety Analysis Report for Nuclear Power Plants,” SRP 11.1, Rev. 2.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to:

- GDC-60, Control of Releases of Radioactive Materials to the Environment, is described in FSAR Section 3.1.2.60.

  The design for radioactivity control is based on the requirements of 10 CFR 20, 10 CFR 50, and 10 CFR 50, Appendix I, for normal operations and for any transient situation that might reasonably be anticipated to occur.

The REMODCM provides requirements for system operation, dose calculations, and monitoring requirements that ensure compliance with effluent limits. Actual measured concentrations of radioactivity released and real time dilution or dispersion estimates are required to verify compliance with effluent limits. Therefore, operation within the requirements of the REMODCM ensures compliance with effluent limits.

The calculated annual radiation doses to the maximum individual from liquid and gaseous pathways are presented in FSAR Appendix 11A. The calculated annual radiation doses are below the design objectives of 10 CFR 50, Appendix I, as shown in FSAR Table 11A-16.

The expected radioactivity concentrations in the liquid discharge are determined using models and assumptions contained in NUREG-0017. The concentration from each of the parent liquid waste streams following treatment are presented in FSAR Tables 11.2-4 and 11.2-7 for the expected and design conditions, respectively. Liquid releases to the environment are listed in FSAR Tables 11.2-5 and 11.2-6 for the *expected* nuclide concentrations prior and subsequent to dilution with the circulating water discharge system. FSAR Tables 11.2-8 and 11.2-9 provide similar data for *design* nuclide concentrations prior and subsequent to dilution with the circulating water discharge system. A summary of the estimated expected annual radioactivity doses is presented in FSAR Appendix 11A. FSAR Table 11.2-10 presents the design nuclide concentration releases to the unrestricted area in terms of fraction of MPC limits described in 10 CFR 20, Appendix B, Table II, Column 2. The results indicate that the sum of the fractions of MPC values does not exceed the limits in 10 CFR 20.

FSAR Table 11.3-2 lists the parameters utilized to determine the radioactive source term for gaseous effluents. FSAR Tables 11.3-5 through 11.3-10 give the calculated sources of radioactive nuclide inventory released via gaseous effluents. FSAR Table 11.3-1 gives the expected radioactive gaseous isotope releases from each release point assumed in terms of curies per year per nuclide. FSAR Table 11.3-11 provides the design releases for the release points. A summary of the estimated expected annual radioactivity doses is presented in FSAR Appendix 11A. A summary of design release concentrations at the site boundary, MPC and fraction of MPCs are presented in FSAR Tables 11.3-8, 11.3-9 and 11.3-10.

NUREG-1838, “Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3,” dated August 1, 2005, defines the scope of license renewal. The radiological source term is not within the scope of license renewal since it is an analytical product of the operational performance of plants systems and components in conjunction with regulatory limits that have been imposed on radiological releases.

2.9.1.2 Technical Evaluation

2.9.1.2.1 Introduction

As stated in Section 2.10.1.2.4.2, there are no changes as a result of the SPU to existing radioactive waste systems (gaseous and liquid) design, plant operating procedures or waste inputs as defined by NUREG-0017, Revision 1. Therefore, a comparison of releases can be made based on current vs. SPU inventories/radioactivity concentrations in the reactor coolant and secondary coolant/steam. As a result, the impact of the SPU on radwaste releases and Appendix I doses can be estimated using scaling techniques.

Scaling techniques based on NUREG-0017, Revision 1 methodology were utilized to assess the impact of SPU on radioactive gaseous and liquid effluents at MPS3. Use of the adjustment factors presented in NUREG-0017, Revision 1 allows development of coolant activity scaling factors to address SPU.

The SPU analysis utilized the plant core power operating history during the years 2001 to 2005, the reported gaseous and liquid effluent and dose data during that period, NUREG-0017, Revision 1, equations and assumptions and conservative methodology to estimate the impact of operation at the analyzed SPU core power level. The results were then compared to the comparable data from current operation on radioactive gaseous and liquid effluents and the consequent normal operation off-site doses.

2.9.1.2.2 Analysis

Section 2.10.1.2.4.2 defines the methodology utilized to define the source terms associated with radioactive waste systems (gaseous and liquid).

2.9.1.2.3 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The radiation source terms were not revised as part of the MPS3 License Renewal. Therefore, there is no impact on the license renewal related to the SPU radiation source terms.

2.9.1.2.4 Results

The impact on the radwaste and effluent discharges is discussed in Section 2.10.1.2.4.3. The SPU has no significant impact on the expected annual radwaste effluent doses (i.e., this analysis demonstrates that the estimated doses following SPU will remain a small percentage of allowable Appendix I doses - see Table 2.10.1-2).

2.9.1.3 Conclusion

DNC has reviewed the radioactive source term associated with the proposed SPU and concludes that the proposed parameters and resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. DNC further concludes that the proposed radioactive source term meets the requirements of 10 CFR 20, 10 CFR 50, Appendix I, and GDC-60. Therefore, DNC finds the proposed SPU acceptable with respect to source terms.

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

2.9.2.1 Regulatory Evaluation

DNC reviewed the DBA radiological consequences analyses. The radiological consequences analyses reviewed are the LOCA, FHA, REA, MSLB, SGTR, LRA, and small line break outside Containment. The DNC review for each accident analysis included: (1) the sequence of events; and (2) models, assumptions, and values of parameter inputs used by the licensee for the calculation of the total effective dose equivalent (TEDE).

The acceptance criteria for radiological consequences analyses using an alternate source term are based on:

- 10 CFR 50.67, insofar as it sets standards for radiological consequences of a postulated accident;
- RG 1.183 for events with a higher probability of occurrence; and
- GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, as defined in 10 CFR 50.2, for the duration of the accident.

Specific review criteria are contained in SRP Section 15.0.1, and guidance from Matrix 9 of RS-001

MPS3 Current Licensing Basis

The MPS3 design was reviewed in accordance with NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants” (NUREG-0800), SRP 15.0.1, Rev. 0.

As noted in the FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the design criteria is discussed in the FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of the MPS3 design relative to:

- GDC-19, Control Room, is described in FSAR Section 3.1.2.19.

  The control room provided is equipped to operate the unit safely under normal and accident conditions. Its shielding and ventilation design permits continuous occupancy of the control room for the duration of a DBA without the dose to personnel exceeding 5 rem whole body.

  The auxiliary shutdown panel located in the west switchgear room has equipment, controls, and instrumentation to accomplish, in conjunction with controls and indication located on the adjacent 460V emergency switchgear, a prompt hot shutdown and a safety grade cold shutdown. The panel is physically located outside the control room. Thus, the uninhabitability of the control room would have no effect on the availability of the auxiliary shutdown panel and adjacent controls (FSAR Section 7.4.1.3).

The design of the control building (FSAR Section 3.8.4), which houses the control room and the auxiliary shutdown panel area, conforms to Criterion 19. FSAR Section 9.4.1 describes the control building ventilation system. Control room habitability is discussed in FSAR Section 6.4. Fire protection systems are discussed in FSAR Section 9.5.1.

2.9.2.1.1 Topics Common to Accident Analyses (Current Licensing Basis)

The following discussion provides the current licensing basis for several topics that are common to each accident analysis.

The methodology used to evaluate the control room and offsite doses resulting from the LOCA, Fuel Handling Accident, SGTR Accident, MSLB Accident, Locked Rotor Accident, and RCCA Ejection Accident employ the alternate source term (AST) as described in RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," in conjunction with TEDE radiological units and limits.

2.9.2.1.1.1 Computer Codes

The radiological consequence calculations for each of the accidents are performed utilizing the RADTRAD-NAI computer code system. The SCALE computer code was used to develop source terms used in the analyses and calculate shine doses. ARCON96 was used to develop the control room X/Qs.

2.9.2.1.1.2 Source Term

The radiological consequence calculations for each of the accidents utilize the source terms as defined in RG 1.183.

The core radionuclide inventory utilized to determine source term releases is provided in FSAR Table 15.0-7. It was generated using the ORIGEN code. ORIGEN is part of the SCALE computer code system. The isotopes and the associated curies at the end of a fuel cycle were input to RADTRAD-NAI. The CEDE and EDE dose conversion factors were taken from Federal Guidance Reports 11 and 12.

2.9.2.1.1.3 RCS and Secondary Concentrations

FSAR Table 15.0-10 provides the Technical Specification concentrations for each nuclide for RCS and secondary side water.

2.9.2.1.1.4 Atmospheric Dispersion Factors (X/Q)

The EAB, LPZ, and control room X/Q values used accident analyses are listed in FSAR Table 15.0-11.

2.9.2.1.1.5 Control Room

FSAR Table 15.6-12 provides assumptions regarding control room habitability analyses.

The control room envelope pressurization system (CREPS) is not credited with operating and providing a positive pressure in the control room. Therefore, during the one-hour period that the CREPS should be operating, the control room is assumed to be at a neutral pressure. During periods of neutral pressure in the MPS3 control room, unfiltered inleakage is 350 cfm. During periods of positive pressure in the MPS3 control room provided by the control room emergency ventilation system (CREVS), unfiltered inleakage is 100 cfm.

The CREVS filter efficiencies are conservatively assumed at 90 percent for both elemental and aerosol and 70 percent for organic iodines.

2.9.2.1.1.6 Containment Parameters

Assumptions are made regarding the containment free volume, containment wall thickness, containment dome thickness, distance from the containment to the MPS3 control room, and the containment inner radius.

2.9.2.1.2 **Analysis of Radiological Consequences for a LOCA (Current Licensing Basis)**

2.9.2.1.2.1 Introduction

The following provides the current licensing basis for the analysis of radiological consequences associated with a LOCA.

On September 13, 2005, DNC submitted a license amendment request to modify the method for actuating the RSS. It includes a reanalysis to the LOCA radiological consequences analysis that accounts for the delay in RSS switchover and credits continual RSS spray removal of iodines after operation of the QSS is terminated. The analysis was conducted in accordance with the AST methodology. DNC supplemented the license amendment request in letters dated June 13, 2006, and August 14, 2006. The NRC approved the license amendment request on September 20, 2006.

The design basis LOCA scenario for radiological calculations is initiated assuming a major rupture of the primary reactor coolant system piping. In order to yield radioactive releases of the magnitude specified in RG 1.183, it is also assumed that the ECCS does not provide adequate core cooling, such that significant core melting occurs. This general scenario does not represent any specific accident sequence, but is representative of a class of severe damage incidents that were evaluated in the development of the RG 1.183 source term characteristics. Such a scenario would be expected to require multiple failures of systems and equipment and lies beyond the severity of incidents evaluated for design basis transient analysis.

The LOCA radiological analysis includes dose from several sources. They are: 1) Containment Leakage Plume; 2) ECCS Component Leakage; 3) RWST Vent; 4) Shine from the plume; 5) Shine from containment; and 6) Shine from the control room filter loading. Doses are calculated at the EAB for the worst-case two-hour period, at the LPZ, and in the MPS3 Control Room. The methodology used to evaluate the Control Room and offsite doses resulting from a LOCA was consistent with RG 1.183.

2.9.2.1.2.2 Basis Data and Assumptions

The basic data and assumptions for the LOCA radiological consequences analysis are listed in Table 10 of the DNC letter dated September 13, 2005.

2.9.2.1.2.3 Source Term

The analysis of the radiological consequences for a LOCA utilizes core release fractions and core release phases from Tables 2 and 4 of RG 1.183, respectively. The core inventory for the current licensing basis is presented in FSAR Table 15.0-7. The CEDE and EDE dose conversion factors were taken from the Federal Guidance Reports 11 and 12.

2.9.2.1.2.4 Iodine Spray Removal Coefficients

The removal coefficient for elemental iodine by sprays is assumed constant at 20 per hour. Sprays will remove elemental iodine until a decontamination factor (DF) of 200 is reached.

The removal coefficients for particulate iodine by sprays were determined to be:

QSS	DF < 50	12.37 per hour
QSS and RSS	DF < 50	14.11 per hour
RSS	DF < 50	7.77 per hour
	DF > 50	0.78 per hour

An elemental iodine decontamination factor (DF) of 200 was calculated at 2.636 hours, after which time credit for removal of elemental iodine is assumed to end. A particulate iodine DF of 50 was calculated at 2.045 hours.

2.9.2.1.2.5 Deposition

A reduction in airborne radioactivity in the containment by natural deposition within containment was credited. The model used is described in NUREG/CR-6189 and is incorporated into the RADTRAD computer code. This model is called the Powers model and it’s used for aerosols in the unsprayed region and set for the 10th percentile.

2.9.2.1.2.6 Mixing

The volume of containment that is covered by quench spray is 1,166,200 ft^3 (49.63 percent). The QSS becomes effective at 71 seconds. At 2,710 seconds post- LOCA, the RSS becomes effective and the sprayed coverage of containment increases to 1,515,858 ft^3 (64.5 percent) during the time when both spray systems are operating. At 6,620 seconds the QSS ends due to RWST inventory depletion and RSS continues to operate for the duration of the accident. The spray coverage of containment during operation of only the RSS is 1,102,000 ft^3. The mixing rate during all spray operation is 2 turnovers of the unsprayed volume per hour.

2.9.2.1.2.7 SLCRS Bypass

Filtered releases were modeled at the Millstone stack and Auxiliary building ventilation vent.

The analysis addresses a plant specific issue of unfiltered releases due to damper bypass and duct leakage from the plant ventilation systems. Credit was taken for 50 percent mixing in the ESF Building, MSV Building, Hydrogen Recombiner Building, Enclosure Building, and each floor of the Auxiliary building.

The control room analysis relied on operator action to trip breakers for the ESF Building, Auxiliary building, and MSV Building normal exhaust fans. This action was assumed to be performed 1 hour and 20 minutes post-LOCA.

Unfiltered releases out of the ESF Building, MSV Building, Hydrogen Recombiner Building, Enclosure Building, and each floor of the Auxiliary building were modeled as an unfiltered stack, ventilation vent, or ground release.

The percentage of containment leakage into a building is based on the location and size of the electrical and mechanical penetrations, and equipment and personnel hatches in the primary containment wall. These percentages are multiplied by the containment leak rate to determine the amount of leakage into each of the areas.

2.9.2.1.2.8 Containment Release Rate

The containment leakage consists of filtered and bypass leakage. The bypass leak rate bypasses the secondary containment and is released unfiltered at ground level directly into the containment. The total containment leak rate (La) is 0.3 percent per day. The entire containment leak rate bypasses the secondary containment until the SLCRS drawn down time of 2 minutes. The bypass leak rate is assumed to be 0.06 * La or 0.018 percent per day after SLCRS draw down time. The leak rate is reduced by one-half at 24 hours for offsite calculations and at 1 hour for control room calculations.

2.9.2.1.2.9 ECCS Leakage

The ECCS fluid consists of the contaminated water in the sump of the containment. This water contains 40 percent of the core inventory of iodine, 5 percent released to the sump water during the gap release phase (30 minutes) and 35 percent released to the sump water during the early in-vessel phase during the next 1.3 hours. During a LOCA the highly radioactive ECCS fluid is pumped from the containment sump to the recirculation spray headers and sprayed back into the containment sump. Also, following a design basis LOCA, valve realignment occurs to switch the suction water source for the ECCS from the RWST to the containment sump.

ECCS leakage develops when emergency safety features (ESF) systems circulate sump water outside containment and leaks develop through packing glands, pump shaft seals and flanged connections. Technical Specification 6.8.4a, Primary Coolant Sources Outside Containment Program Manual calculates this leakage at 4,780 cc/hr. The ECCS analysis makes use of twice the program limit or 10,000 cc/hr for ECCS leakage in accordance with RG 1.183, Appendix A. The leakage of recirculating sump fluids commences at 2,530 seconds, which is the earliest time of recirculation. The start time is less than the RSS effective time by 3 minutes, which is the time assumed to fill the system.

The temperature of the containment sump is conservatively assumed to reach a maximum of 240°F. At this maximum temperature, a flash fraction of 0.03 is calculated. However, per the guidance of R.G.-1.183, a conservative

flash fraction of 0.1 was used for the ECCS leakage during the entire event. The water volume of the sump at 2,530 seconds is 86,814 ft^3 and is conservatively assumed to remain constant even though QSS continues to dilute the sump from the RWST.

2.9.2.1.2.10 RWST Back-leakage

Following a design basis LOCA, valve realignment occurs to switch the suction water source for the ECCS from the RWST to the containment sump. In this configuration, motor operated valves (MOVs) and check valves in the normal suction line from the RWST and MOVs in the recirculation line provide isolation between this contaminated flow stream and the RWST.

RADTRAD-NAI is used to calculate the dose from leakage of ECCS fluid through these valves back into the RWST with subsequent release of the evolved iodine through the vent at the top of the RWST to the environment.

The RADTRAD-NAI source term used to model the ECCS leakage into the RWST contains 40 percent of the core inventory iodine, 5 percent released to the sump water during the gap release phase (30 minutes) and 35 percent released to the sump water during the early in-vessel phase during the next 1.3 hours. The iodine form is 97 percent elemental and 3 percent organic in accordance with RG-1.183.

The leak paths back to the RWST are:

- CHS Alternate Recirculation Leakage
- RHS Leakage through V*43
- SIH Pump Recirculation
- RHS A and B suction
- CHS Suction
- SIH Suction

2.9.2.1.2.11 Results

Table 2.9.2-4 presents the associated worst case TEDE for the EAB, LPZ, and control room. All doses are less than the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.1.3 Analysis of Radiological Consequences for a SGTR Accident (Current Licensing Basis)

2.9.2.1.3.1 Introduction

The following provides the current licensing basis for the analysis of radiological consequences associated with a SGTR.

A SGTR is a break in a tube carrying primary coolant through the steam generator. This postulated break allows primary liquid to leak to the secondary side of one of the steam generators (denoted as the affected generator) with an assumed release to the environment through the main steam pressure relief valve. The main steam pressure relief valve on the affected steam generator is assumed to open to control steam generator pressure at the beginning of the event, and then fail fully open after operator action was taken to close the main steam pressure relief valve.

2.9.2.1.3.2 Source Term

Initial radionuclide concentrations in the primary and secondary systems for the SGTR accident are determined based on the maximum Technical Specification levels of activity (1 μCi/gm dose equivalent I-131) in accordance with RG 1.183. The SGTR accident analysis indicates that no fuel rod failures occur as a result of these transients. Thus, radioactive material releases were determined by the radionuclide concentrations initially present in primary liquid, secondary liquid, and iodine spiking. These values are the starting point for determining the curie input for the RADTRAD-NAI code runs.

The nuclide concentrations in the RCS and secondary side water are as presented in FSAR Table 15.0-10.

RG 1.183 stipulates that SGTR accidents consider iodine spiking above the value allowed for normal operations based both on a pre-accident iodine spike and a concurrent accident spike. For Millstone Unit 3, the maximum iodine concentration allowed by Technical Specifications as the result of an iodine spike is 60 μCi/gm dose equivalent I-131. This value is treated as the pre-accident iodine spike and is listed in MPS3 Table 15.0-12. RG 1.183 defines a concurrent iodine spike as an accident initiated value 335 times the appearance rate corresponding to the Technical Specification limit for normal operation (1 μCi/gm DEQ I-131 RCS TS limit) for a period of 8 hours. The concurrent iodine spike appearance rates based on 335 times the 1.0 μCi/gm DEQ I-131 concentration are listed in MPS3 Table 15.6.3-6.

2.9.2.1.3.3 Analysis

MPS3 Table 15.6.3-4 provides the assumptions used in the analysis of the radiological consequences associated with a SGTR. MPS3 Table 15.6.3-3 provides the mass releases that occur during a SGTR.

The affected generator discharges steam to the environment for 2946 seconds (0.8183 hours) until the generator is isolated a second time by closure of the main steam pressure relief valve isolation valve. Break flow into the affected steam generator continues until 5596 seconds

(1.554 hours), at which time the RCS is at a lower pressure. Additional releases from the affected steam generator are modeled from 2-8 hours to complete depressurization of the steam generator early in the event to maximize the dose consequences. Depressurization of the steam generator is necessary to initiate Residual Heat Removal System (RHRS) cooling.

The intact generator (3 generators modeled as one) discharges steam for a period of 18 hours until the primary system has cooled sufficiently to allow a switchover to the RHRS, at 11 hours, plus a 7 hour period of concurrent steaming. The additional 7 hours of steaming are required to reduce the system heatload to the point where RHRS can remove all the decay heat crediting only safety grade equipment to achieve cold shutdown and steaming is no longer required for cooldown. No fuel damage is predicted as a result of a SGTR. Therefore, consistent with the current licensing analysis basis, the SGTR analysis was performed assuming both a pre-accident iodine spike and a concurrent accident iodine spike. In addition, the impact of a coincident loss-of-offsite power (LOOP) at the time of tube rupture was considered.

In accordance with RG 1.183, the release of noble gases has been analyzed without mitigation. Two noble gas release scenarios were considered; one with holdup and another without holdup. Without holdup, the affected steam generator discharges steam to the environment for 1.554 hours after which the break flow stops and the main steam pressure relief valve isolation valve is closed. Holdup of noble gases in the affected steam generator was investigated, because of the operator action to close the main steam pressure relief valve isolation valve at 0.8183 hours with the break flow continuing to enter the generator until 1.554 hours and subsequent release at 2 hours. From the period of 0.8183 hours to 2 hours, noble gases are held up in the steam generator. No benefit was derived from modeling holdup as the scenario that resulted in the higher dose consequences was used to determine the dose from noble gases.

2.9.2.1.3.4 Results

The total TEDE to the EAB, LPZ and Millstone Unit 3 Control Room from a SGTR is summarized in Table 2.9.2-4 for the concurrent and pre-accident iodine spike cases. The pre-accident iodine spike results in the highest dose consequences for both offsite and the control room. All doses are within the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.1.4 Analysis of Radiological Consequences for a MSLB Accident (Current Licensing Basis)

2.9.2.1.4.1 Introduction

The following provides the current licensing basis for the analysis of radiological consequences associated with a MSLB.

The MSLB accident begins with a break in one of the main steam lines leading from a steam generator (affected generator) to the turbine. In order to maximize control room dose, the break is assumed to occur in the turbine building. The affected steam generator releases steam for 55.2 hours, at which time the RCS has cooled down to 212F and release via this pathway terminates. The 55.2-hour steaming period is based on the time necessary to cooldown crediting safety grade equipment only. Also, it is expected that the affected generator will dry out in 56.3 seconds post-MSLB. Loss of Off-site Power is assumed. As a result, the condenser is unavailable and cool down of the primary system is through the release of steam from the intact generators. The release from the intact generators continues for 18 hours through the main steam pressure relief valves until the RHRS can fully remove decay heat.

2.9.2.1.4.2 Source Term

The MSLB analysis uses the primary and secondary liquid source terms provided in FSAR Table 15.0-10, the pre-accident iodine spike source term provided in FSAR Table 15.0-12, and the concurrent iodine spike source term provided in FSAR Table 15.0-13. The RCS pre-accident iodine spike concentrations are based on 60 μCi/gm dose equivalent I-I31. The iodine release rates into RCS due to a concurrent iodine spike concentrations are based on 500 times the equilibrium iodine appearance rate.

2.9.2.1.4.3 Analysis

MPS3 Table 15.1-3 provides the assumptions utilized in the analysis of the radiological consequences associated with the MSLB accident. In accordance with RG 1.183, Appendix E, two independent cases are evaluated. Case one assumes a pre-accident iodine spike, while the second case assumes a concurrent iodine spike.

The source term resulting from the radionuclides in the primary system coolant and from the iodine spiking in the primary system is transported to the steam generators by the leak-rate limiting condition for operation (1 gpm) specified in the Technical Specifications. The maximum amount of primary to secondary leakage allowed by the Technical Specifications to any individual steam generator is 500 gallons per day. This leakage (500 gpd equivalent to 0.35 gpm) was assigned to the affected generator.

For the affected generator, the release pathway is assumed to pass directly into the turbine building with no credit taken for holdup, partitioning or scrubbing by the steam generator liquid. No credit is taken for any holdup or dilution in the Turbine Building. From the Turbine Building it passes to the environment and to the control room. During the first 56.3 seconds post-trip, the affected steam generator is assumed to steam dry as a result of the MSLB, releasing all of the nuclides in the secondary coolant that were initially contained in the steam generator. During the first 55.2 hours, the primary coolant is also assumed to leak into the affected steam generator at the rate of 500 GPD with all activity released unmitigated to the environment. After 55.2 hours the RCS will have cooled to below 212F and the release via this pathway terminates. The transport model utilized for noble gases, iodine and particulates was consistent with RG 1.183, Appendix E.

The remainder of the 1 gpm primary side to secondary side leakage, 0.65 gpm, was assigned to the 2 intact generators. This leakage continues for 18 hours until shutdown cooling is credited for decay heat removal. The third intact generator is assumed to have a failed closed main steam pressure relief valve, which reduces the holdup volume to 2 generators instead of 3, but the steaming rate has not been reduced, which maximizes the release rate.

There are several nuclide transport models associated with the intact steam generators. Together, they ensure proper accounting of gross gamma, iodine and noble gas releases. The first pathway releases gross gamma activity, at the Technical Specification limit of 100/E_{bar} to the SG liquid volume at 0.65 gpm.

Releases of radionuclides initially in the steam generator liquid and those entering the steam generator from the primary to secondary leakage flow are released as a result of secondary liquid boiling. Due to moisture carryover, 1 percent of the particulates in the steam generator bulk liquid are released to the environment at the steaming rate. Radionuclides initially in the steam space do not provide any significant dose contribution and are not considered. The transport to the environment of noble gases from the primary coolant and from particulate daughters occurs without any mitigation or holdup.

The pre-accident iodine spike is modeled in the same manner as the gross gamma model previously discussed. The concurrent iodine spike model is modeled in the same manner as the gross gamma model but the iodine spike occurs for 8 hours after which the activity remaining in the primary coolant continues to be released for the remainder of the 18 hours from the intact steam generators and 55.2 hours from the affected steam generator.

2.9.2.1.4.4 Results

The total TEDE to the EAB, LPZ and Millstone Unit 3 Control Room from a MSLB is summarized in Table 2.9.2-4 for the concurrent and pre-accident spike. The concurrent spike results in the highest dose consequences for both offsite and the control room. All doses are within the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.1.5 Analysis of Radiological Consequences for a Locked Rotor Accident (Current Licensing Basis)

2.9.2.1.5.1 Introduction

The following provides the current licensing basis for the analysis of radiological consequences associated with a Locked Rotor Accident (LRA).

The LRA begins with instantaneous seizure of the rotor or break of the shaft of a reactor coolant pump under 4-loop operation. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer, which results in assumed fuel damage (7 percent) due to entering into DNB. Although there is no increase in the leak rate of primary coolant to the secondary side in the LRA, a larger amount of activity (from the failed fuel) may be transported to the secondary side via any preexisting leaks in the steam generators.

2.9.2.1.5.2 Source Term

The LRA utilizes the core inventory described in the LOCA analysis. The analyses are based on 7 percent of the failed fuel activity being released to the RCS.

2.9.2.1.5.3 Analysis

FSAR Table 15.3-3 provides the assumptions utilized to determine the radiological consequences associated with a locked rotor accident.

A turbine trip and coincident loss of offsite power are incorporated into the analysis. The release is through a stuck open main steam pressure relief valve, which represents an assumed, single, active failure on the affected steam generator. Operator action is credited with closure of the main steam pressure relief valve in 20 minutes.

Steaming from the intact steam generators continues for 11 hours at which point the RCS is cooled to 350°F and the RHR system can supplement the cooling concurrent with the steam. Steaming continues for an additional 7 hours. At this point, the release terminates because the RHR system is capable of removing 100 percent of the decay heat.

The release scenario uses the Technical Specification primary to secondary leakage limits of 1 gpm total and 500 gpd from the affected steam generator. It assumes the maximum Technical Specification leakage from the affected steam generator of 500 GPD, which equates to 0.35 gpm and lasts for 20 minutes until operator action isolates that release pathway. The balance of the 1-gpm limit (0.65 gpm) is released from the intact steam generators over the course of 18 hours until shutdown cooling can be implemented to fully remove decay heat. At this time, the release from the intact steam generators is terminated when the main steam pressure relief valves are assumed closed.

The RADTRAD-NAI computer code is used to model the time dependent transport of radionuclides, from the primary to secondary side and out to the environment via main steam pressure relief valves.

2.9.2.1.5.4 Results

Table 2.9.2-4 presents the associated worst case TEDE for the EAB, LPZ, and control room. All doses are less than the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.1.6 Analysis of Radiological Consequences for a RCCA Ejection Accident (Current Licensing Basis)

2.9.2.1.6.1 Introduction

The following provides the current licensing basis for the analysis of radiological consequences associated with a RCCA ejection accident (REA).

The REA is defined as the mechanical failure of a control rod mechanism pressure housing, resulting in the ejection of a 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. Two release paths are considered for the REA: containment leakage and the secondary system.

2.9.2.1.6.2 Source Term

The REA utilizes the core inventory described in the LOCA analysis. The release of the core source term is adjusted for the fraction of fuel rods assumed to fail during the accident and the fractions of core inventory assumed to be in the pellet-to-clad gap.

The analysis is based on a WCAP that determined 10 percent failed fuel and 0.25 percent melted fuel occurs during an REA.

2.9.2.1.6.3 Analysis

The containment release transport assumptions and methodology are similar to the LOCA, with a few exceptions. The exceptions are:

1. The core release fractions are based on RG 1.183, Appendix H. The core release fraction for breached fuel is 10 percent of the noble gases and iodines in the gap. The core release fractions for melted fuel are 100 percent noble gases and 25 percent iodines.

2. Containment sprays do not initiate due to a REA. Therefore, there are no consequences from ECCS leakage and RWST back-leakage.

3. Natural deposition in the containment is not assumed.

4. Containment leak rate is reduced by 50 percent at 24 hours for both offsite and control room analyses.

5. The safety injection signal is initiated 2 minutes after a REA. Therefore, the isolation of the control room and drawdown of secondary containment are delayed by 2 minutes.

The second release path is via the secondary system. The activity in the secondary system release is based on RG 1.183, Appendix H. The core release fractions are 100 percent of the noble gases and 50 percent of the iodines based on the consequences of 10 percent failed fuel and 0.25 percent melted fuel resulting from the REA. The iodines released from the steam generators are assumed to be 97 percent elemental and 3 percent organic. The primary-to-secondary leak rate of 1 gpm, which is specified in the technical specifications, exists until shutdown cooling is in operation and release from the steam generators terminate. All noble gas radionuclides released to the secondary system are released to the environment without reduction or mitigation. The condenser is not available due to a loss of offsite power.

A partition coefficient for iodine of 100 is assumed in the steam generators. The primary-to-secondary leak continues until the primary system pressure is less than the secondary side system pressure. This time period was conservatively assumed to be 1200 seconds.

FSAR Table 15.4-4 provides the assumptions used in the analysis of the radiological consequences associated with an RCCA ejection.

2.9.2.1.6.4 Results

The total TEDE to the EAB, LPZ, and the MPS3 Control Room from a RCCA ejection accident is summarized in Table 2.9.2-4. The containment pathway results in the highest dose consequences for both offsite and the control room. All doses are within the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.1.7 Analysis of Radiological Consequences for a Fuel Handling Accident (Current Licensing Basis)

2.9.2.1.7.1 Introduction

The following provides the current licensing basis for the analysis of radiological consequences associated with a fuel handling accident.

The design basis scenario for the radiological analysis of the FHA assumes that cladding damage has occurred to all of the fuel rods in one fuel assembly plus 50 rods in the struck assembly. The rods are assumed to instantaneously release their fission gas contents to the water surrounding the fuel assemblies. The analyses include the evaluation of FHA cases that occur in both the containment and the Fuel Building. Essentially, all radioactivity released from the damaged fuel is assumed to release over a two-hour period through an open penetration in the containment or the Fuel Building.

2.9.2.1.7.2 Source Term

The core inventory is as described for the LOCA analysis, and is used for the FHA with a 100-hour decay time. As provided in RG 1.183, Appendix B, the fraction of fission product in the gap was taken from RG 1.183, Table 3. All particulate nuclides are assumed retained by the water resulting in a release of noble gases and non-particulate halogens.

For the FHA analyses, the core inventory was used to calculate the gap activity of one fuel assembly plus 50 rods for input to RADTRAD-NAI. The amount of fuel damage is the same whether the FHA is in the Fuel Building or Containment. Due to the depth of water in either the refuel pool or spent fuel pool, a decontamination factor of 200 is used for the iodines released from the fuel. The resulting chemical form of the radioiodine released from the water is 57 percent elemental iodine and 43 percent organic iodide.

2.9.2.1.7.3 Analysis

FSAR Table 15.7-8 provides the assumptions utilized in the analysis to determine the radiological consequences associated with a fuel handling accident. FSAR Table 15.7-10 provides the iodine and noble gas inventory in fuel rod gaps for a fuel handling accident prior to decay.

This evaluation does not credit operability or operation of the Containment purge system, Auxiliary building or Fuel Building ventilation. This evaluation assumes that the personnel hatch, equipment hatch and penetrations are open for the duration of the 2-hour release.

Releases from the Fuel Building or Containment to the environment are at a rate of 3.454 air changes per hour. This assures that greater than 99.9 percent of the activity in the Fuel Building and Containment analyses were released within 2 hours. The release rate is conservative in that it biases the bulk of the release (i.e., >80 percent) to occur within the first half hour of the event. No credit is taken for filtration of the release from either the Fuel Building or Containment. Additionally, no credit is taken for dilution or mixing of the activity released to the Fuel Building or Containment air volumes.

The most conservative release point was chosen from either the containment or fuel building releases resulting in both analyses being the same. Based on X/Qs, the conservative release point for offsite consequences is the containment equipment hatch. The conservative release point for control room consequences is the ventilation vent stack.

2.9.2.1.7.4 Results

The MPS3 FHA assumes a two-hour release without building integrity or filtration for either the Containment or Fuel Building FHA. The associated worst case TEDE is presented in Table 2.9.2-4. All doses are less than the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.1.8 Analysis of Radiological Consequences for a Small Line Break Outside Containment (Current Licensing Basis)

2.9.2.1.8.1 Introduction

The following provides the current licensing basis for the analysis of radiological consequences associated with a small line break outside Containment.

The most severe pipe rupture with regard to radioactivity release during normal plant operation occurs in the charging system. This would be a complete severance of the 3-inch letdown line just outside containment, but between the outboard letdown isolation valve and letdown heat exchanger, at rated power condition.

2.9.2.1.8.2 Source Term

The plant is assumed to be operating at the technical specification primary coolant activity and primary-to-secondary leakage through all four steam generators.

One hundred percent of the noble gases contained in the primary coolant are released to the environment due to the leak. The fraction of iodine release to the environment is derived from a calculated fraction of approximately 0.40 of the primary coolant flashing during pipe leakage. This is based on a direct release of primary coolant at primary coolant temperature, which conservatively bounds potential accident sequences. Due to transients in the core at the time of the accident, it is assumed that an iodine spike occurs concurrently with the letdown line rupture.

2.9.2.1.8.3 Analysis

The assumptions used to perform this evaluation are summarized in FSAR Table 15.6-2. The technical specification activity listed in FSAR Table 15.6-4 together with the atmospheric dispersion values listed in FSAR Table 15.0-11 (for containment releases) are used to compute the doses to the EAB (0–2 hr).

The complete severance of the letdown line results in a LOCA at the rate of approximately 152 gpm that may not result in the activation of the ESF systems for the duration of the release. This implies that the SLCRS and Auxiliary building filters are not in operation and the releases to the environment from the severed line are assumed to be at ground level. The time needed to identify and isolate the rupture is conservatively assumed to be 30 minutes.

2.9.2.1.8.4 Results

The radiological consequences of the postulated small line break are reported in FSAR Table 15.0-8 (Table 2.9.2-4). The resulting doses to the EAB are less than a small fraction of the 10 CFR 100 guidelines; i.e., less than 30 Rem to the thyroid and less than 2.5 rem to the whole body.

2.9.2.1.9 License Renewal

NUREG-1838, "Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3," dated August 1, 2005, defines the scope of license renewal. Evaluation of the specific transient analysis was not within the scope of License Renewal.

2.9.2.2 Technical Evaluation

The SPU involves the reanalysis of the design basis radiological analyses for the following accidents: 1) LOCA, 2) SGTR accident, 3) MSLB accident, 4) LRA, 5) REA, 6) FHA; and 7) Small line break outside Containment. The radiological consequence analyses for the various accidents were performed using input assumptions consistent the proposed SPU conditions. As appropriate, the TEDE is determined at the EAB for the limiting 2-hour period, at the LPZ outer boundary for the duration of the accident, and in the control room for 30 days.

The proposed changes to the radiological consequence analyses are identified in Table 2.9.2-4.

2.9.2.2.1 Changes to Topics Common to Accident Analyses (SPU Analysis)

The following provides a discussion of the changes associated with topics common to accident analyses.

2.9.2.2.1.1 Computer Codes

The SPU analyses continue to utilize the RADTRAD-NAI and SCALE computer codes. There were no changes to the X/Qs, thus, ARCON 96 was not reutilized in the SPU analyses.

2.9.2.2.1.2 Source Term

The core inventory is revised to reflect the SPU conditions. Table 2.9.2-1 provides the core inventory associated with the power uprate. This table will replace FSAR Table 15.0-7. It was generated using the ORIGEN code. ORIGEN is part of the SCALE computer code system. The isotopes and the associated curies at the end of a fuel cycle were input to RADTRAD-NAI. The CEDE and EDE dose conversion factors were taken from Federal Guidance Reports 11 and 12.

2.9.2.2.1.3 RCS and Secondary Concentrations

The RCS and secondary side nuclide concentrations were revised to reflect the SPU conditions. The RCS and secondary side nuclide concentrations are provided in Table 2.9.2-2. This information will replace the information currently provided in FSAR Table 15.0-10.

2.9.2.2.1.4 Atmospheric Dispersion Factors (X/Qs)

There are no changes to the X/Qs. The SPU analyses utilize the X/Qs for the EAB, LPZ, and control room established in FSAR Table 15.0-11.

2.9.2.2.1.5 Control Room

The SPU analyses to determine radiological consequences utilize the assumptions for control room habitability established in FSAR Table 15.6-12, except for the following:

- The assumptions regarding the CREVS filter efficiencies are changed as noted in Table 2.9.2-4 to be 95 percent for all forms of iodine. This assumption was changed to reflect the requirements of the Technical Specification 3/4.7.7 plus an additional safety factor of at least 2 per NRC Generic Letter 99.02.
- The CREVS is assumed to be in the filtered recirculation mode of operation within 30 minutes of an FHA involving a spent fuel assembly. A modification will be developed to implement this assumption.

2.9.2.2.1.6 Containment

The SPU analyses for post-accident radiological consequences utilize the assumptions established in the current licensing basis regarding the containment structure, and its distance to the MPS3 control room.

2.9.2.2.1.7 Secondary Side Releases for Non-LOCA Accidents

The radiological analyses calculated steam releases from the steam generator using the same methodology as the current calculation. The steam releases are determined considering the following:

- Dissipation of RCS stored energy
- Dissipation of steam generator stored energy
- Total core heat generated
- Total core heat dissipated
- Mass of auxiliary feedwater injected
- Mass of steam vented to the environment

Secondary side steam releases from the intact steam generators are assumed throughout the accident sequence until the reactor coolant system temperature is reduced to cold shutdown conditions. The mass releases are divided into four time periods: from 0 to 2 hours, from 2 to 11 hours, from 11 to 24 hours, and a time period for simultaneous steaming and RHR operation (from 24 hours to a time defined in the accident analysis. The mass of the secondary side steam release was calculated for the times periods of 0 to 2 hours and 2 to 11 hours. After 11 hours, the steam release rate from the intact generators is assumed to be constant. This constant flow rate is the average steaming rate over the 2 to 11 hour time period. This is conservative, because the steam release rate will decrease as decay heat decreases. The steaming rate has been extended to 24 hours to provide additional margin for RHR entry. During the time period that there is simultaneous steaming and RHR operation, an additional steam release is assumed as defined in Table 2.9.2-4 for each event. Additional details on timing and mass flows for each accident analysis are provided in Table 2.9.2-4.

The secondary side steam releases were calculated for the MSLB (Section 2.6.3.2), LRA (Section 2.8.5.3.2), SGTR (Section 2.8.5.6.2), and REA (Section 2.8.5.4.6), and are discussed in the noted LR sections.

2.9.2.2.2 Changes to Analysis of Radiological Consequences for a LOCA (SPU Analysis)

2.9.2.2.2.1 Introduction

The SPU analysis of the radiological consequences for the LOCA contains differences than the current licensing basis methodology approved by the NRC on September 20, 2006, as described in DNC's license amendment request dated September 13, 2005, as supplemented on June 13 and August 14, 2006. A discussion of the differences is provided below.

2.9.2.2.2.2 Basis Data and Assumptions

Table 2.9.2-4 identifies the changes in assumptions from the current analysis of the post-LOCA radiological consequences, and the SPU analysis of the post-LOCA radiological consequences.

2.9.2.2.2.3 Source Term

As described above, the source term was revised to reflect the SPU conditions.

2.9.2.2.2.4 Iodine Spray Removal Coefficients

The removal coefficient for elemental iodine by sprays was changed from 20 per hour to 10 per hour. This change was made to add additional conservatism to the analysis. Sprays will remove elemental iodine until a decontamination factor (DF) of 200 is reached.

As identified in Table 2.9.2-4, the removal coefficients for particulate iodine by QSS, QSS and RSS, and RSS were determined to be different than those utilized in the current licensing basis due to conservative changes in the assumed QSS and RSS flow rates.

As identified in Table 2.9.2-4, the time to achieve elemental iodine DF of 200, and a particulate iodine DF of 50 were determined to be different than the current licensing basis due to the changes in the QSS and RSS start times and flow rates.

2.9.2.2.2.5 Deposition

There was no change to the methodology utilized to establish the reduction in airborne radioactivity in the containment due to natural deposition within containment.

2.9.2.2.2.6 Mixing

As identified in Table 2.9.2-4, the QSS and RSS effectiveness times were changed in the SPU analysis of the post-LOCA radiological consequences. Various cases for one and two-train operation and start and stop times for QSS and RSS were analyzed. The QSS and RSS effectiveness times identified in Table 2.9.2-4 represent a one-train case with a delayed RSS start time to minimize the time that QSS and RSS operate together.

The SPU analysis utilized the same assumptions as the current licensing basis post-LOCA radiological consequences analysis regarding the QSS and RSS spray coverage and the mixing rate during all spray operation.

2.9.2.2.2.7 SLCRS Bypass

The SPU analysis modified the release points for filtered releases. Instead of utilizing the Millstone stack and Auxiliary building ventilation vent for filtered releases, the SPU post-LOCA radiological consequences analysis assumes that all filtered releases are released from the Auxiliary building ventilation vent. This is a conservation assumption, because the X/Qs from the ventilation vent are higher than the X/Qs from the stack. This assumption also simplifies the dose model by utilizing one release point.

The SPU analysis assumes that the Auxiliary building atmosphere is homogeneously mixed. The Auxiliary building is treated as one compartment with all releases into and out of each elevation combined.

The SPU analysis modified the release points for the unfiltered releases from the Auxiliary building. Instead of utilizing several release points for each elevation of the Auxiliary building, the SPU post-LOCA radiological consequences analysis assumes that all unfiltered releases are released from the Auxiliary building ventilation vent. This is a conservative assumption, because the X/Qs from the ventilation vent are higher than the other X/Qs. This assumption also simplifies the dose model by utilizing one release point.

The SPU analysis no longer takes credit for operator action to trip breakers for the ESF Building, Auxiliary building, and MSV Building normal exhaust fans for the control room dose analysis.

The SPU analysis determined a different percentage break down of the total containment leakage into the secondary containment as identified in Table 2.9.2-4. These changes were due to a change in the assumed ESF building as well as the combination of the Auxiliary building elevations into one large area. The ESF Building free volume was determined based on a calculation, versus an estimate.

2.9.2.2.2.8 Containment Release Rate

The SPU post-LOCA radiological consequences analysis assumptions and model regarding containment leakage remained the same as the current licensing basis, except for those described above regarding SLCRS bypass

2.9.2.2.2.9 ECCS Leakage

ECCS leakage was assumed to commence at an earlier time than the current licensing basis as identified in Table 2.9.2-4. The new time represents a two-train case minus fill time, which maximizes ECCS leakage by having the RSS pumps start at the earliest possible time.

As identified in Table 2.9.2-4, the SPU analysis assumed that the temperature of the containment sump water is slightly lower than assumed in the current licensing basis. This change is due to the later start time for RSS. Because a two-train ECCS case will result in a lower sump temperature, the sump temperature at 1 hour was used based on a 1 train ECCS case. Note: the amount of iodine that flashes remains at 10 percent.

2.9.2.2.2.10 RWST Back-leakage

The SPU analysis does not contain any changes to the analysis regarding RWST Back-leakage.

2.9.2.2.2.11 Results

Table 2.9.2-4 presents the associated worst case TEDE for the EAB, LPZ, and control room. All doses are less than the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.2.3 Changes to Analysis of Radiological Consequences for a SGTR Accident (SPU Analysis)

Table 2.9.2-4 identifies the differences in the input parameters between the current licensing basis and the SPU analyses regarding the radiological consequence analysis for the SGTR accident.

2.9.2.2.3.1 Introduction

The methodology for conducting the analysis of the radiological consequences for the SGTR remains the same as the current licensing, except for the changes required to reflect the increase in power and to reflect the revision in the assumptions regarding the plant cooldown. The specific changes are identified in Table 2.9.2-4, and are discussed below.

2.9.2.2.3.2 Source Term

The nuclide concentrations in the RCS and secondary side, the pre-accident iodine spike source term, and the concurrent iodine spike source term have been revised to reflect SPU conditions. The revised values are presented in Table 2.9.2-2, Table 2.9.2-3a and Table 2.9.2-3b.

2.9.2.2.3.3 Analysis

The specific changes in assumptions regarding the secondary side releases for the SGTR are identified in Table 2.9.2-4, along with the rationale for the change. Additional information is provided in Section 2.9.2.2.1.7.

Different values for the initial steam generator water mass and RCS volume were assumed regarding the concurrent iodine spike and preaccident iodine spike cases. The values chosen maximize the dose.

2.9.2.2.3.4 Results

Table 2.9.2-4 presents the associated worst case TEDE for the EAB, LPZ, and control room. All doses are less than the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.2.4 Changes to Analysis of Radiological Consequences for a MSLB Accident (SPU Analysis)

2.9.2.2.4.1 Introduction

The methodology for conducting the analysis of the MSLB radiological consequences remains the same as the current licensing, except for the changes required to reflect the increase in power, and the revision in the assumptions regarding the plant cooldown. The specific changes are identified in Table 2.9.2-4, and are discussed below.

2.9.2.2.4.2 Source Term

The nuclide concentrations in the RCS and secondary side, the pre-accident iodine spike source term, and the concurrent iodine spike source term have been revised to reflect SPU conditions. The revised values are presented in Table 2.9.2-2, Table 2.9.2-3a and Table 2.9.2-3b.

2.9.2.2.4.3 Analysis

The specific changes in assumptions regarding the secondary side releases for the MSLB are identified in Table 2.9.2-4, along with the rationale for the change. Additional information is provided in Section 2.9.2.2.1.7.

2.9.2.2.4.4 Results

Table 2.9.2-4 presents the associated worst case TEDE for the EAB, LPZ, and control room. All doses are less than the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.2.5 Changes to Analysis of Radiological Consequences for a Locked Rotor Accident (SPU Analysis)

2.9.2.2.5.1 Introduction

The methodology for conducting the analysis of the radiological consequences for the LRA remains the same as the current licensing basis, except for the changes required to reflect the increase in power and the revision in the assumptions regarding the plant cooldown. The specific changes are identified in Table 2.9.2-4, and are discussed below.

2.9.2.2.5.2 Source Term

The core inventory has been modified to reflect the increase in power. The revised core inventory is presented in Table 2.9.2-1.

2.9.2.2.5.3 Analysis

The specific changes in assumptions regarding the secondary side releases for the LRA are identified in Table 2.9.2-4, along with the rationale for the change. Additional information is provided in Section 2.9.2.2.1.7.

2.9.2.2.5.4 Results

Table 2.9.2-4 presents the associated worst case TEDE for the EAB, LPZ, and control room. All doses are less than the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.2.6 Changes to Analysis of Radiological Consequences for a RCCA Ejection Accident (SPU Analysis)

2.9.2.2.6.1 Introduction

The methodology for conducting the analysis of the radiological consequences for the REA remains the same as the current licensing basis, except for the changes required to reflect the increase in power, the revision in the assumptions regarding the plant cooldown, and a change in methodology for analyzing releases from SLCRS bypass that were identified in the LOCA section. The specific changes are identified in Table 2.9.2-4, and are discussed below.

2.9.2.2.6.2 Source Term

The core inventory has been modified to reflect the increase in power. The revised core inventory is presented in Table 2.9.2-1.

2.9.2.2.6.3 Analysis

The specific changes in assumptions regarding the secondary side releases for the REA are identified in Table 2.9.2-4, along with the rationale for the change. Additional information is provided in Section 2.9.2.2.1.7.

The changes in the methodology for calculating the dose contribution of the unfiltered releases due to damper bypass and duct leakage from the plant ventilation systems (SLCRS bypass) is discussed in Section 2.9.2.2.2.7.

2.9.2.2.6.4 Results

Table 2.9.2-4 presents the associated worst case TEDE for the EAB, LPZ, and control room. All doses are less than the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.2.7 Changes to Analysis of Radiological Consequences for a Fuel Handling Accident (SPU Analysis)

2.9.2.2.7.1 Introduction

The methodology for conducting the analysis of the radiological consequences associated with the fuel handling accident that involves the drop of a spent fuel assembly remains the same, except for the assumptions regarding 1) the number of rods that are assumed to fail, 2) the fraction of fission product inventory in the gap; and 3) the assumption that the control room emergency ventilation system is placed in the filtered recirculation mode of operation within 30 minutes of a drop of a spent fuel assembly. Table 2.9.2-4 identifies the differences in the input parameters between the current licensing basis and the SPU analyses.

An additional analysis involving the drop of a RCCA handling tool, containing an RCCA (or similar non-fuel component) into the spent fuel pool was performed. The intent of this analysis is to demonstrate that there are no requirements for the operation of the control room emergency ventilation system during these types of activities.

2.9.2.2.7.2 Source Term

Currently, the analysis of the radiological consequences of the fuel handling accident utilizes the gap fractions defined in RG 1.183, Table 3 for 100 percent of the fuel rods that are assumed to fail. However, RG 1.183, Table 3 footnote 11 states the following:

> "The release fractions listed here have been determined to be acceptable for use with currently approved LWR fuel with a peak burnup up to 62,000 MWD/MTU provided that the maximum linear heat generation rate does not exceed 6.3 kw/ft peak rod average power for burnups exceeding 54 GWD/MTU. As an alternative, fission gas release calculations performed using NRC-approved methodologies may be considered on a case by case basis."

Following the SPU, the limiting discharge assembly will have rods with burnup exceeding 54 GWD/MTU and exceeding 6.3 kw/ft peak rod average power. At SPU conditions, it has been determined that 67 percent of the fractured fuel rods are expected to exceed 54 GWD/MTU and 6.3 kw/ft peak rod average power. For these rods, the gap fractions listed in RG 1.25 (as modified by the direction of NUREG/CR-5009) are used with the design peaking factor of 1.7. The design peaking factor conservatively bounds the expected SPU maximum peaking factor of 1.35. The remaining 33 percent of the fuel rods comply with the criteria of RG 1.183, Table 3, footnote 11, and utilize the gap fractions from RG 1.183, Table 3.

The use of gap functions listed in RG 1.25 (as modified by the direction of NUREG/CR-5009) has been approved by the NRC for application to other Dominion plants including MP2 and Kewaunee on September 20, 2004, and March 8, 2007, respectively (References 8 and 9).

However, because of this increase in the release fractions, the control room emergency ventilation system must be placed in the filtered recirculation mode of operation within 30 minutes of the fuel handling accident. This action is required to meet the established dose limits specified in 10 CFR 50.67. A modification will be implemented to address this assumption.

2.9.2.2.7.3 Analysis

2.9.2.2.7.3.1 FHA Involving the Drop of a Spent Fuel Assembly

The current analysis assumption for fuel damage due to a drop of a spent fuel assembly onto the core or the spent fuel pool racks is based upon a generic assumption of one assembly plus 50 rods. For SPU, a MP3 specific calculation has been performed, taking into account energy absorption by the lower nozzle of the dropped assembly and the upper nozzle of the impacted assembly.

The SPU MP3 specific calculation demonstrates that the fuel damage would be limited to one assembly plus 19 rods for a drop of an assembly on the core. This is based on the following assumptions:

- Maximum mass of fuel assembly with a Rod Cluster Control Assembly of 1647 lbm
- Maximum drop height of 13.5 feet
- The dropped assembly is assumed to topple over, resulting in failure of all of the rods in the dropped assembly

A similar calculation was performed for the drop of an assembly in the spent fuel pool. The assumptions for the spent fuel pool are as follows:

- Maximum mass of the fuel assembly, the RCCA and the fuel handling tool of 2027 lbm
- Maximum drop height of 2 feet 8.4 inches.
- The dropped assembly is assumed to topple over, resulting in failure of all of the rods in the dropped assembly.

The damage resulting from a drop of a spent fuel assembly in the core bounds the damage resulting from a drop of a spent fuel assembly in the spent fuel pool for all fuel types in the spent fuel pool.

2.9.2.2.7.3.2 FHA Involving the Drop of a Non-Spent Fuel Assembly

A new analysis of a fuel-handling event involving the drop of a non-spent fuel assembly component into the spent fuel pool was performed to demonstrate that operation of the control room emergency ventilation system is not necessary for these types of activities in the spent fuel pool.

An analysis determined the potential fuel failure of a drop of non-fuel components, such as an RCCA, neutron source or thimble plug. For these components the drop height is limited to 2.7 feet. The results show no fuel damage for all fuel types with the exception of the original core loading of 17 by 17 standard fuel. For this fuel type, used only in the first three cycles of operation, a corrosion mechanism has been identified that reduces the structural capability of the assembly. The calculation shows that for the drop of an RCCA and the RCCA handling tool, the maximum fuel damage is 18 rods. A bounding radiological analysis was performed that assumed 30 rods were damaged as a result of a drop of a non-spent fuel assembly.

The radiological analysis uses the same assumptions and inputs as a FHA involving a drop of a spent fuel assembly except the amount of fuel damage and the availability of the control room emergency ventilation system. The analysis does not assume control room isolation or the operation of the control room emergency ventilation system to meet the limits required by 10 CFR 50.67 and RG 1.183.

2.9.2.2.7.4 Results

Table 2.9.2-4 presents the associated worst case TEDE for the EAB, LPZ, and control room. All doses are less than the limits specified in RG 1.183 and 10 CFR 50.67.

2.9.2.2.8 Changes to Analysis of Radiological Consequences for a Small Line Break Outside Containment (SPU Analysis)

2.9.2.2.8.1 Introduction

The methodology for conducting the analysis of the radiological consequences for the small line break outside containment was modified to incorporate the alternate source term methodology defined by RG 1.183. In addition, the assumptions were revised to reflect the power increase.

2.9.2.2.8.2 Source Term

The small line break outside containment was reanalyzed using the source term as defined by RG 1.183. The analysis methodology applied the guidance of RG 1.183, in conjunction with the TEDE methodology. The nuclide concentrations in the RCS are presented in Table 2.9.2-2.

In addition, the analysis assumes a concurrent iodine spike equivalent to 500 times the equilibrium iodine appearance rate based on 1 μCi/gram I-131 dose equivalent. The concurrent iodine spike source term is revised to reflect SPU conditions. The revised values are presented in Table 2.9.2-3b.

2.9.2.2.8.3 Analysis

The event remains as described in FSAR Section 15.6.2. In the new analysis, the initial RCS water mass was modified for conservatism.

2.9.2.2.8.4 Results

Table 2.9.2-4 presents the associated worst case TEDE for the EAB. The dose is less than the limit specified in RG 1.183 and 10 CFR 50.67 for other accidents that involve a concurrent iodine spike.

2.9.2.2.9 Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Evaluation of the specific transient analyses was not within the scope of License Renewal.

2.9.2.3 Conclusion

Table 2.9.2-4 provides the results of the radiological consequence calculations regarding SPU conditions and the applicable dose acceptance criteria from GDC-19, RG 1.183 and 10 CFR 50.67. The post-accident doses to the EAP, LPZ, and control room remain within the applicable dose acceptance.

2.9.2.4 References

1. DNC letter to the NRC, “Millstone Power Station Unit 3, Proposed Technical Specification Changes, Recirculation Spray System,” dated September 13, 2005.

2. DNC letter to the NRC, “Millstone Power Station Unit 3, Proposed Technical Specification Changes, Recirculation Spray System,” dated June 13, 2006.

3. DNC letter to the NRC, “Millstone Power Station Unit 3, Proposed Technical Specification Changes, Recirculation Spray System,” dated August 14, 2006.

4. NRC letter to DNC, “Millstone Power Station Unit No. 3 – Issuance of Amendment Re: Recirculation Spray System (TAC NO. MC8327),” dated September 20, 2006.

5. Regulatory Guide 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors.”

6. Regulatory Guide 1.25, “Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling Storage Facility for Boiling and Pressurized Water Reactors,” 1972.

7. NUREG/CR-5009, “Assessment of the Use of Extended Burnup Fuel in Light Water Power Reactors,” 1988.

8. NRC Letter to DNC, “Millstone Power Station, Unit No. 2 – Issuance of Amendment Re: Selective Implementation of Alternate Source Term (TAC No. MB6479), dated September 20, 2004

9. NRC Letter to Dominion Energy Kewaunee, “Kewaunee Power Station – Issuance of Amendment Re: Radiological Accident Analysis and Associated Technical Specifications Change (TAC NO. MC9715),” dated March 8, 2007.

Table 2.9.2-1

Nuclide	Curies		Nuclide	Curies		Nuclide	Curies
Ba139	1.70e+08		La141	1.61e+08		Sr 90	9.05e+06
Ba140	1.79e+08		La142	1.52e+08		Sr 91	1.12e+08
Ba141	9.47e+07		Mo 99	1.84e+08		Sr 92	1.15e+08
Br 84	1.70e+07		Nb 95	1.67e+08		Tc 99m	1.64e+08
Ce141	1.64e+08		Nd147	6.61e+07		Te127	8.62e+06
Ce143	1.50e+08		Np239	2.04e+09		Te127m	1.44e+06
Ce144	1.29e+08		Pr143	1.47e+08		Te129	3.03e+07
Cm242	4.83e+06		Pu238	4.06e+05		Te129m	6.17e+06
Cm244	5.56e+05		Pu239	3.30e+04		Te131	7.65e+07
Cs134	1.98e+07		Pu240	4.62e+04		Te131m	1.97e+07
Cs136	6.29e+06		Pu241	1.49e+07		Te132	1.42e+08
Cs137	1.25e+07		Rb 86	2.19e+05		Te133	6.29e+07
Cs138	1.69e+08		Rb 88	6.47e+07		Te133m	7.54e+07
I131	9.89e+07		Rb 89	5.47e+07		Te134	1.39e+08
I132	1.45e+08		Rh105	1.03e+08		Xe133	2.03e+08
I133	2.03e+08		Ru103	1.60e+08		Xe135	5.60e+07
I134	2.13e+08		Ru105	1.11e+08		Xe135m	3.66e+07
I135	1.89e+08		Ru106	5.83e+07		Xe138	8.46e+07
Kr 85	1.05e+06		Sb127	8.73e+06		Y 90	9.46e+06
Kr 85m	2.27e+07		Sb128m	1.35e+07		Y 91	1.19e+08
Kr 87	4.14e+07		Sb129	3.11e+07		Y 92	1.23e+08
Kr 88	6.11e+07		Sb131	5.06e+07		Y 93	9.40e+07
La140	1.86e+08		Sr 89	9.10e+07		Zr 95	1.66e+08
						Zr 97	1.57E+08

Table 2.9.2-2

Isotope	RCS, 1 μCi/gm DEQ I-131 & gross gamma RCS concentration, μCi/gm	Secondary Side Liquid, 0.1 μCi/gm DEQ I-131 & gross gamma concentration, μCi/gm
KR85M	3.20E-01	
KR87	2.48E-01	
KR88	6.50E-01	
XE131M	5.66E-02	
XE133M	2.24E-01	
XE133	7.42E+00	
XE135M	2.76E-01	
XE135	1.61E+00	
XE138	1.91E-01	
BR83	2.06E-02	
BR84	1.02E-02	4.69E-07
CS134	6.76E+00	7.44E-03
CS134M	1.38E-02	
CS136	1.03E+00	1.11E-03
CS137	4.73E+00	5.34E-03
CS138	2.94E-01	8.67E-06
RB86	4.26E-02	4.60E-05
RB88	6.78E-01	2.00E-05
RB89	4.23E-02	1.68E-06
BA137M	4.45E+00	1.31E-04
BA139	2.28E-02	6.74E-06
BA140	1.10E-03	6.59E-07
CE144	1.30E-04	7.84E-08
CO58	1.70E-02	1.06E-05
CO60	2.10E-03	1.31E-06
FE55	1.70E-03	1.05E-06
FE59	1.10E-03	6.62E-07

Table 2.9.2-2

Isotope	RCS, 1 μCi/gm DEQ I-131 & gross gamma RCS concentration, μCi/gm	Secondary Side Liquid, 0.1 μCi/gm DEQ I-131 & gross gamma concentration, μCi/gm
LA140	3.69E-04	1.98E-07
LA142	7.13E-05	
MN54	3.30E-04	2.02E-07
MO99	1.54E+00	8.83E-04
MO101	6.15E-03	2.44E-07
NB95	1.69E-04	9.99E-08
NP239	1.98E-02	1.10E-05
RU106	5.90E-05	3.66E-08
SR89	8.83E-04	5.41E-07
SR90	5.74E-05	3.53E-08
SR91	3.81E-04	1.47E-07
SR92	2.76E-04	
TC99M	7.99E-01	2.36E-04
TC101	5.99E-03	2.37E-07
TE127M	9.08E-04	5.65E-07
TE129	3.95E-03	
TE129M	3.87E-03	2.39E-06
TE131	3.69E-03	
TE131M	9.77E-03	5.02E-06
TE132	8.11E-02	4.64E-05
TE133	2.51E-03	9.94E-08
TE133M	5.58E-03	4.19E-07
TE134	8.52E-03	6.40E-07
Y91	4.18E-03	2.54E-06
Y91M	2.27E-04	
ZR95	1.67E-04	1.03E-07
I131	7.81E-01	8.04E-02

Table 2.9.2-2

Isotope	RCS, 1 μCi/gm DEQ I-131 & gross gamma RCS concentration, μCi/gm	Secondary Side Liquid, 0.1 μCi/gm DEQ I-131 & gross gamma concentration, μCi/gm
I132	3.20E-01	1.44E-02
I133	1.19E+00	1.09E-01
I134	1.81E-01	4.19E-03
I135	7.00E-01	5.00E-02

Table 2.9.2-3a Pre-Accident Iodine Spike RCS Concentrations

Nuclide	Iodine Activity in RCS at 1.0 DEQ I-131 μCi/gm	Iodine Activity in RCS at 60 times 1.0 DEQ I-131 μCi/gm
I-131	7.81E-01	4.68E+01
I-132	3.20E-01	1.92E+01
I-133	1.19E+00	7.12E+01
I-134	1.81E-01	1.09E+01
I-135	7.00E-01	4.20E+01

Table 2.9.2-3b Concurrent Iodine Spike RCS Concentrations

Nuclide	Appearance Rate for 1 μCi/gm DEQ I-131, μCi/sec	Spike =335 SGTR Release Rate μCi/sec	Spike =500 MSLB/Small Line Break Release Rate μCi/sec
I-131	6.06E+03	2.03E+06	3.03E+06
I-132	7.86E+03	2.63E+06	3.93E+06
I-133	1.12E+04	3.76E+06	5.61E+06
I-134	9.46E+03	3.17E+06	4.73E+06
I-135	9.44E+03	3.16E+06	4.72E+06

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Common Changes			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Power Level	3636 MWt	3723 MWt (3650 MWt + 2% Uncertainty)	The proposed value is equal to 102% of the proposed power level (3650 MWt). Note: the previous calculation assumed a power level that was higher than 102% of the current licensed power level of 3411 MWt.
Control Room Ventilation Filter Efficiencies	HEPA 90% Charcoal 90% (elemental) 70% (methyl)	HEPA 95% Charcoal 95% (elemental) 95% (methyl)	Filter efficiencies changed to be consistent with the requirements of the Technical Specification 3/4.7.7 plus an additional safety factor of at least 2 per NRC Generic Letter 99-02.
Core Inventory	FSAR Table 15.0-7	Table 2.9.2-1	Revised to reflect SPU conditions.
Primary Coolant Concentrations	FSAR Table 15.0-10	Table 2.9.2-2	Revised to reflect SPU conditions.
Secondary Coolant Concentrations	FSAR Table 15.0-10	Table 2.9.2-2	Revised to reflect SPU conditions.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Common Changes Associated with Determining Dose Due to SLCRS Bypass in LOCA and RCCA Ejection Accident			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Modeled Location of Filtered Releases	Filtered releases from the Millstone stack (including fumigation) and Auxiliary building ventilation vent were modeled at their specific locations.	All filtered releases are assumed released from the Auxiliary building ventilation vent.	This is acceptable, because the X/Qs for the ventilation vent are higher than those of the stack resulting in higher doses. It also simplifies the dose model by utilizing one release point.
Modeled Location of Unfiltered Releases from Auxiliary building	Unfiltered releases from various points in the Auxiliary building are discharged out either stack or Auxiliary building ventilation vent.	Unfiltered releases from the Auxiliary building are assumed to occur from the Auxiliary building ventilation vent.	This is acceptable, because the ventilation vent X/Q is larger than that from a stack release. It also simplifies the dose model by utilizing one release point.
Mixing of Auxiliary building Atmosphere	The releases from the Auxiliary building were modeled at several locations (elevations)	The Auxiliary building atmosphere is homogeneously mixed. The Auxiliary building is treated as one compartment with all releases into and out of each elevation combined.	Simplifies the LOCA dose model

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Common Changes Associated with Determining Dose Due to SLCRS Bypass in LOCA and RCCA Ejection Accident			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Percentage of Total Containment Leakage into the Secondary Containment	ESF Building 10.59% MSV Building 23.64% Enclosure Building / H2 Recombiner Building 8.28% Aux. Building, El. 4'-6" 12.43% Aux. Building, El. 24'-6" 21.08% Aux. Building, El. 43'-6" 20.82% Aux. Building, El. 66'-6" 3.17%	ESF Building 10.59% MSV Building 23.31% Enclosure Building / H2 Recombiner Building 8.47% Aux. Building 57.63%	Minor changes for the MSV and Enclosure/H2 Recombiner Building due to a change in method of calculating value. Auxiliary building elevations combined into one large building as a simplifying assumption.
Operator Action to Secure Normal Exhaust Fans	For Control Room habitability, the analysis relied on an operator action to trip breakers for the ESF Bldg, Aux. Bldg, and MSVB normal exhaust fans 1 hour 20 minutes post-LOCA.	All referenced non-safety related fans continue to operate for the 30-day duration of the accident resulting in unfiltered leakage through associated boundary dampers	Eliminate the requirement to take operator action post-LOCA to trip the breakers for selected fans. This is acceptable, because allowing the unfiltered release to continue for the entire time maximizes the dose.
ESF Building Free Volume	168,373 ft^3	225,000 ft^3	Current basis was an estimate of the free volume. Proposed basis was calculated.
Auxiliary building Free Volume, All Elevations	913,500 ft^3	914,000 ft^3	A change in method of calculating value.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

LOCA			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Quench Spray System Effectiveness Time	71 – 6,620 seconds	80 – 10,000 seconds	Analyzed various cases for one and two-train operation and start and stop of QS and RS. These times resulted in the most conservative dose. It represents a one-train case with delayed start time and maximum QS flow to minimize operation time.
Recirculation Spray System Effectiveness Time	2710 seconds to 30 days	5500 seconds to 30 days	Analyzed various cases for one and two-train operation and start and stop of QS and RS. These times resulted in the most conservative dose. It represents a one-train case with delayed start time to minimize time at which QS and RS are operating together.
QSS Flow Rate (ft^3/hr)	31,040	28,846	Conservative value chosen from the containment pressure analysis.
RSS Flow Rate (ft^3/hr)	20,702	17,308	Conservative value chosen from the containment pressure analysis.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

LOCA			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Elemental Iodine Removal Coefficient	20 per hour	10 per hour	This change was made to add additional conservatism to the calculation.
Particulate Iodine Removal Coefficient for Quench Spray	12.37/hr for DF < 50	11.5/hr for DF < 50	This change is due to the new QSS flow rate used in the analysis.
Particulate Iodine Removal Coefficient for Quench and Recirculation Spray	14.11/hr for DF < 50	13.57/hr for DF < 50 1.36/hr for DF > 50	This change is due to new QSS and RSS flow rates used in the analysis.
Particulate Iodine Removal Coefficient for Recirculation Spray	7.77/hr for DF < 50 0.78/hr for DF > 50	0.65hr for DF > 50	This change is due to the new RSS flow rate used in the analysis.
Time at which Elemental Iodine DF of 200 is Reached	2.636 hours	2.33 hours	This change is due to the changes in the QSS and RSS start time and flow rates and removal coefficient.
Time at which Particulate Iodine DF of 50 is Reached	2.045 hours	2.063 hours	This change is due to the changes in the QSS and RSS start time and flow rates.
ECCS Leak Initiation Time	2530 seconds	2500 seconds	This time represents a two-train case minus fill time so as to start RS pumps at earliest possible time for start of ECCS leakage.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

LOCA			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Sump Volume at the Start Time of ECCS Leakage	6.495E5 gallons	Approximately 1.67E5 gallons	This assumption is made to maximum the iodine concentration in the containment sump volume.
ECCS Sump Water Temperature	240°F (maximum)	230°F (maximum)	The later start time of RS resulted in a slightly lower sump fluid temperature. The amount of iodine that flashes remains at 10%.
ECCS Leakage Location	80% ESF Building 20% Auxiliary building, 24'-6" elevation	100% Auxiliary building	This is acceptable, because the ventilation vent has a higher X/Q than an ESF building ground release. It is also a simplifying assumption.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Locked Rotor Accident			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Release Duration for Intact Steam Generators (hours)	18	35.75	The time to achieve the RHR entry condition (RCS temperature at 350°F) was conservatively delayed to 24 hours. This is followed by 11.75 hours of steaming concurrent with RHR operation.
Total Steam Flows to Atmosphere from Intact Steam Generators (lbm)	0-2 hours 251,000 2-8 hours 1,031,000 8-11 hours 820,800 11-18 hours 1,915,359	0-2 hours 432,000 2-11 hours 1,328,000 11-24 hours 1,918,222 24-35.75 hours 196,515	The new 0 to 2 hour and 2 to 11 hour steam releases are based on a new Westinghouse analysis of the LRA. To determine the mass release for the 11 to 24 hour time period, the release rate calculated for the 2 to 11 hour period is conservatively assumed to continue until the RHR entry condition is attained at 24 hours. The concurrent RHR steaming period is based on an actual analysis versus a conservative assumption of DWST inventory assumed in the current analysis.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Locked Rotor Accident			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Initial Steam Generator Liquid Mass (grams per steam generator)	4.414 E+07	4.582 E+07	Revised to reflect SPU conditions.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Rod Ejection Accident			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Release Duration from the Secondary System (hours)	18	35.75	The time to achieve the RHR entry condition (RCS temp at 350°F) was conservatively delayed to 24 hours. This is followed by 11.75 hours of steaming concurrent with RHR operation.
Steam Release (lbm)	0 – 1200 seconds 2.000 E+05 2 – 11 hours 1.547 E+06 11 – 18 hours 1.916 E+06	0 – 1200 seconds 2.000 E+05 2 – 24 hours 3.246 E+06 24 – 35.75 hours 1.974 E+05	The new 0 to 2 hour and 2 to11 hour steam releases are based on a new Westinghouse analysis of the REA. To determine the mass release for the 11 to 24 hour time period, the release rate calculated for the 2 to 11 hour period is conservatively assumed to continue until the RHR entry condition is attained at 24 hours. The concurrent RHR steaming period is based on an actual analysis versus a conservative assumption of DWST inventory assumed in the current analysis.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Rod Ejection Accident			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Steam Generator Liquid Contents (lbm per steam generator)	97,222	100,933	Conservatively increased based on the Westinghouse analysis of steam releases for the SPU.
RCS mass (lbm)	5.194 E+05	4.458 E+05	Conservatively decreased the RCS mass, resulting in high concentrations of nuclides in the RCS following fuel damage.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Steam Generator Tube Rupture			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Release Duration through Affected Steam Generator	0 – 2946 seconds 2 – 8 hours	0 – 2702 seconds 2 – 11 hours	These values are from the revised SGTR Thermal and Hydraulic Analysis.
Release Duration through Intact SG (hours)	0 – 18	0 – 35.75	The time to achieve the RHR entry condition (RCS temp at 350°F) was conservatively delayed to 24 hours. This is followed by 11.75 hours of steaming concurrent with RHR operation.
Operate Action Time to Initiate Safety Injection Termination (minutes)	3	6	This value is from the revised SGTR Thermal and Hydraulic Analysis.
RCS Volume (ft^3)	11750	11750 - Preaccident Iodine Spike 10000 - Concurrent Iodine Spike	Dose consequences were sensitive to RCS volume, values were chosen to maximize dose.
Initial Steam Generator Liquid Mass (lbm/SG)	97,222	97,222 – Preaccident Iodine Spike 100,933 – Concurrent Iodine Spike	Values were chosen to maximize dose.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Steam Generator Tube Rupture			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Mass Flow to Environment through Affected Steam Generator (lbm)	0 – 2 hours 302,812 2 – 8 hours 34,100	0 – 2 hours 357,940 2 – 11 hours 40,920	These values are from the revised SGTR Thermal and Hydraulic Analysis. However, the dose calculation assumes the flow is through the affected steam generator for the entire period to maximize the effluent release (i.e., no credit is assumed for operation of the condenser).
Mass Flow to Environment through Intact Steam Generators (lbm)	0 – 2 hours 839,800 2 – 8 hours 941,000 8 – 18 hours 2,387,036	0 – 2 hours 867,240 2 – 11 hours 1,678,380 11 – 24 hours 2,424,240 24 – 35.75 hours 196,555	The new 0 to 2 hour and 2 to 11 hour steam releases are based on a new Westinghouse analysis of the SGTR accident. To determine the mass release for the 11 to 24 hour time period, the release rate calculated for the 2 to 11 hour period is conservatively assumed to continue until the RHR entry condition is attained at 24 hours. The concurrent RHR steaming period is based on an actual analysis versus a conservative assumption of DWST inventory assumed in the current analysis.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Steam Generator Tube Rupture			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Total RCS Break Flow (lbm)	0–2 hours 223,349	0–2 hours 229,790	This value is from the revised SGTR Thermal and Hydraulic Analysis.
RCS Break Flow Terminates (hours)	1.554	1.781	This value is from the revised SGTR Thermal and Hydraulic Analysis.
Flashed RCS Break Flow (lbm)	13,175	15,646	These values are from the revised SGTR Thermal and Hydraulic Analysis.
Iodine Spike Appearance Rates for SGTR	FSAR Table 15.6.3-6	Table 2.9.2-3b	Revised to reflect SPU conditions.
Specific Activities in the Primary and Secondary Coolant - Iodine	FSAR Table 15.6.3-5	Table 2.9.2-2 and Table 2.9.2-3b	Revised to reflect SPU conditions.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Main Steam Line Break			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Iodine Spike Release Rates for MSLB	FSAR Table 15.0-13	Table 2.9.2-3b	Revised to reflect SPU conditions.
Specific Activities in Reactor Coolant - Iodines	FSAR Table 15.0-12	Table 2.9.2-3a	Revised to reflect SPU conditions.
Duration of Release for Intact Steam Generators (hours)	18	36.25	Revised to reflect SPU conditions using bounding assumptions. The time to achieve the RHR entry condition (RCS temperature at 350°F) was conservatively delayed to 24 hours. This is followed by a period of steaming concurrent with RHR operation.
Duration of Release for Affected Steam Generator (hours)	55.2	65.75	Revised to reflect SPU conditions using bounding assumptions.
Initial Steam and Water Release from Affected Steam Generator	164,200 lbm in the first 56.3 seconds	165,000 lbm in the first 16.5 seconds	Revised to reflect SPU conditions using bounding assumptions.
Long Term Steam Release from the Affected Steam Generator for	9,664 lbm for 0 – 55.2 hours	11,511 lbm for 0 – 65.75 hours	Revised to reflect SPU conditions using bounding assumptions.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Main Steam Line Break			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Steam Release from Unaffected Steam Generators (lbm)	0 – 2 hours 409,000 2 – 8 hours 983,000 8 – 18 hours 2,736,159	0 – 2 hours 430,000 2 – 11 hours 1,280,000 11 – 24 hours 1,848,600 24 – 36.25 hours 196,400	The new 0 to 2 hour and 2 to 11 hour steam releases are based on a new Westinghouse analysis of the MSLB accident. To determine the mass release for the 11 to 24 hour time period, the release rate calculated for the 2 to 11 hour period is conservatively assumed to continue until the RHR entry condition is attained at 24 hours. The concurrent RHR steaming period is based on an actual analysis versus a conservative assumption of DWST inventory assumed in the current analysis.
Initial Steam Generator Contents (lbm/SG)	164,200	165,000	Updated value.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Fuel Handling Accident			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Fuel Damaged	1 assembly plus 50 rods	1 assembly plus 19 rods	New analysis took into account the impact energy absorbed by the rods and fuel assembly structure.
Control Room Emergency Ventilation System Assumed to be in Filtered Recirculation Mode within 30 minutes of event	Not Required	Modification will be implemented to address assumption.	To provide operating margin with regarding to fuel handling accident.
Percentage of Fuel Rods that Exceed the Requirements of Footnote 11 of RG 1.183	0%	67%	A fuel census was performed by nuclear core design, which determined that assuming 67% of the fuel rods exceeding the criteria of RG 1.183, Table 3, footnote 11 would bound projected loading plans and operating strategies. For these rods, the gap fractions listed in RG 1.25 (as modified by the direction of NUREG/CR-5009) are used with the design peaking factor of 1.7.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Fuel Handling Accident			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Gap Activity Fractions	Halogens 0.08 Noble Gases 0.1	For fuel assemblies that comply with footnote 11 of RG 1.183 (33%) I-131 0.08 Kr-85 0.10 Other 0.05 - noble gases - halogens For fuel assemblies that do not comply with footnote 11 of RG 1.1.83 (67%) I-131 0.12 Kr-85 0.30 Other 0.10 - noble gases - halogens	67% of the fuel rods damaged by this accident do not comply with footnote 11 of RG 1.183. The gap activity fractions for these rods comply with the requirements of RG 1.25, as modified by NUREG/CR-5009.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Fuel Handling Accident			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Drop of a Non-Spent Fuel Assembly Component	No analysis provided in FSAR	New Analysis added to the FSAR	An analysis of a non-spent fuel assembly component in the spent fuel pool has been added. This analysis establishes that the control room emergency ventilation system is not required to be operable when moving non-spent fuel assemblies in the SFP.

Table 2.9.2-4
Summary of Proposed Changes to the Radiological Analyses

Small Line Break Outside Containment			
Parameter	**Current Licensing Basis**	**Proposed Change**	**Reason for Change**
Dose Acceptance Criteria	A small fraction of the dose limits of 10 CFR 100 Whole body Limit of 30 rem Thyroid Limit of 2.5 rem	RG 1.183 limit for accidents involving a coincident iodine spike TEDE limit of 2.5 rem	Adopt Alternate Source Term methodology consistent with other analyses.
Iodine Spike Release Rates	FSAR Table 15.6-5	Table 2.9.2-3b	Revised to reflect SPU conditions.
Technical Specification Iodine and Noble Gas Concentrations	FSAR Table 15.6-4	Table 2.9.2-2	Revised to reflect SPU conditions.
Primary coolant mass (lbm)	3.8E+04	4.483E+05	RCS value was chosen as to maximize technical specification activity released from the break.

Table 2.9.2-5
Summary of Dose Consequences

Design Basis Accident	EAB (rem)	LPZ (rem)	Control Room (rem)
SPU – LOCA	5.5E+00	1.3E+00	3.4E+00
CLB – LOCA (GSI 191 Analysis)	*7.5E+00*	*1.8E+00*	*1.9E+00*
Dose Criteria	2.5E+01	2.5E+01	5.0E+00
SPU – FHA	2.7E+00	1.5E-01	4.8E+00
CLB – FHA	*2.4E+00*	*1.3E-01*	*4.9E+00*
Dose Criteria	6.3E+00	6.3E+00	5.0E+00
SPU – FHA for Non-Spent Fuel Assembly Drop	—	—	4.3 E+00
Dose Criteria			5.0E+00
SPU – SGTR Accident (1)	2.2E+00	2.0E-01	3.3E+00
CLB – SGTR Accident	*2.1E+00*	*1.8E-01*	*3.0E+00*
Dose Criteria	2.5E+01	2.5E+01	5.0E+00
SPU – SGTR Accident (2)	1.0E+00	2.0E-01	1.7E+00
CLB – SGTR Accident	*9.0E-01*	*9.0E-02*	*1.3E+00*
Dose Criteria	2.5E+00	2.5E+00	5.0E+00
SPU – MSLB Accident (1)	9.6E-02	4.4E-02	1.6E+00
CLB – MSLB Accident	*9.1E-02*	*3.6E-02*	*1.2E+00*
Dose Criteria	2.5E+01	2.5E+01	5.0E+00
SPU – MSLB Accident (2)	4.0E-01	2.2E-01	3.6E+00
CLB – MSLB Accident	*3.6E-01*	*1.8E-01*	*3.0E+00*
Dose Criteria	2.5E+00	2.5E+00	5.0E+00
SPU – Locked Rotor Accident	2.2E+00	3.9E-01	3.5E+00
CLB – Locked Rotor Accident	*2.3E+00*	*3.7E-01*	*3.2E+00*
Dose Criteria	2.5E+00	2.5E+00	5.0E+00
SPU – RCCA Ejection Accident			
Containment	5.9E-01	3.1E-01	2.0E+00
Secondary Side	*1.2E-01*	*1.6E-02*	*5.1E-02*
CLB – RCCA Ejection Accident			
Containment	8.7E-01	4.8E-01	8.3E-01
Secondary Side	*1.2E-01*	*1.5E-02*	*5.3E-02*
Dose Criteria	6.3+E00	6.3+E00	5.0E+E00

Table 2.9.2-5
Summary of Dose Consequences

Design Basis Accident	EAB (rem)	LPZ (rem)	Control Room (rem)
SPU – SLB Outside Containment	2.5E+00 (TEDE)	NA	NA
CLB – SLB Outside Containment	2.1E+01 (THY) 1.5E-01(WB)	NA	NA
Dose Criteria	2.5E+00 (TEDE)		
1. Pre-accident iodine spike 2. Concurrent iodine spike			

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

2.10.1.1 Regulatory Evaluation

DNC conducted its review in this area to ascertain the overall effects the proposed SPU will have on both occupational and public radiation doses and to determine that DNC has taken the necessary steps to ensure that any dose increases will be maintained as low as is reasonably achievable (ALARA). The DNC review included an evaluation of any increases in radiation sources and how this may affect plant area dose rates, plant radiation zones and plant area accessibility. DNC evaluated how personnel doses needed to access plant vital areas following an accident are affected. DNC considered the effects of the proposed SPU on plant effluent levels and any effect this increase may have on radiation doses at the site boundary.

The acceptance criteria for occupational and public radiation doses are based on:

- 10 CFR 20
- GDC-19

Specific review criteria are contained in SRP Sections 12.2, 12.3, 12.4, and 12.5 and guidance is provided in Matrix 10 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed in accordance with NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants,” SRP Sections 12.2, 12.3, 12.4 and 12.5, Rev. 2. DNC took exception to SRP 12.2 in that FSAR Section 12.2 does not tabulate the calculated concentrations of radioactive material expected during accident conditions. The justification provided for that omission is that during accident conditions, local surveys and measurements will be performed as required and exposures will be limited to the requirements of NUREG-0737.

As noted in FSAR Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria is discussed in FSAR Sections 3.1.1 and 3.1.2.

Specifically, the adequacy of MPS3 design relative to conformance to:

- GDC-19 is described in the FSAR Section 3.1.2.19, Control Room (Criterion 19).

  The control room provided is equipped to operate the unit safely under normal and accident conditions.

Additional details that define the MPS3 licensing basis with respect to radiation protection of plant personnel and the public are described in various FSAR sections as described below:

- Section 12.3.1, Shielding, discusses the radiation shielding design and MPS3 commitment to 10 CFR 20.

- Section 12.3.1.3, Accident Shielding, discusses control room design and post-accident access to vital areas, and MPS3 compliance with NUREG 0737, II.B.2.
- Section 11.2, Liquid Waste Management Systems, Section 11.3, Gaseous Waste Management Systems and Section 11.4, Solid Waste Management System discuss radioactivity in effluents resulting from operation of the liquid, gaseous and solid waste management systems respectively, and MPS3 compliance with 10 CFR 20 and 10 CFR 50, Appendix I.
- Section 12.1, Ensuring that Occupational Radiation Exposures are as Low as Reasonably Achievable (ALARA), discusses DNC policy to implement a program that meets the requirements of 10 CFR 20 and ensure that the occupational radiation exposures at its nuclear facilities are kept ALARA.

Technical Specification 6.9.1.4, Radioactive Effluent Release Report, requires that an annual report will be submitted in accordance with the requirements of 10 CFR 50.36a, and consistent with the objectives of the Offsite Dose Calculation Manual, which requires conformance with 10 CFR 50 Appendix I.

As discussed in FSAR Sections 11.5 and 12.3.4, the radiation monitors installed at MPS3 can be classified into four categories: a) area, b) airborne, c) process and d) effluent. Area and airborne radiation monitors are included as radiation protection features and provide radiation/radioactivity monitoring to support control of radiation exposure of plant personnel. Process and effluent radiation monitors are provided in support of radioactivity monitoring in gaseous and liquid process streams, or effluent release points to unrestricted areas, to support control of radiation exposure of both plant personnel and the public. Post-accident monitoring is provided in accordance with RG 1.97 requirements to give notice of significant radioactive releases from the plant. The high alarm and alert setpoints for the radiation monitors are based on meeting the above objectives.

As discussed in FSAR Section 12.3.1.3.2, in response to NUREG 0737, Item II.B.2, a plant radiation shielding design review of vital areas and equipment was conducted in order to ensure adequate personnel access to vital areas and protection of safety equipment for post-design basis accident operations.

The design basis vital area access review that supports MPS3's licensing basis relative to vital area dose rates/operator doses while performing post-LOCA vital missions is documented in "Proposed License Amendment Request – Post-Accident Access to Vital Areas (PLAR 3-98-6)," dated June 10, 1998 as supplemented by "Proposed License Amendment Request – Post-Accident Access to Vital Areas (PLAR 3-98-6); Request for Additional Information," dated October 30, 1998. NRC acceptance and approval of the vital area access assessment performed by Millstone was documented in a NRC Safety Evaluation Report (SER) "Issuance of Amendment - Millstone Nuclear Power Station, Unit No. 3 (TAC NO. MA2054)," March 1, 1999. Millstone Amendment 201, dated January 8, 2002 (elimination of requirements for Post-Accident Sampling), Amendment 232, dated September 15, 2006 (Alternate Source Term), and Amendment 224, dated June 29, 2005 (elimination of the requirements for hydrogen recombiners and hydrogen monitors) have impacted the vital access requirements/assessment documented in the 1998 License Amendment Request.

Several of the access requirements listed in the 1998 License Amendment were no longer required due to changes in the licensing basis since 1998, specifically access requirements for post-accident sampling (Task 2), to the hydrogen recombiner panel (Task 7), and to initiate hydrogen purge (Task 8). The access requirements for sampling were predicated upon the perceived need for samples of the containment sump, containment atmosphere, and reactor coolant system within a relatively short period of time after an accident occurred. However, post-TMI studies have shown that other means can be employed to determine the degree of core damage and classify events for emergency planning purposes. Consequently, the Post-Accident Sampling System was removed from the Technical Specifications in Amendment 201 using the consolidated line item improvement process (CLIIP) per TSTF-366. Hydrogen recombiners were removed from the Technical Specifications in Amendment 224 per TSTF-447, and the associated NRC SER. In general, post-TMI information determined that hydrogen production in a DBA was sufficiently slow such that other means could be employed to reduce the concentration to below combustible limits, if needed. In the event of a severe accident, the rate of hydrogen production exceeds the capability of the recombiners, causing the recombiners to become an unwarranted ignition source. Therefore, entry into this area was no longer considered necessary for short-term post-accident operations.

Due to a design change, which changed the type of sump pump used in the RSS area of ESF building, Task 10 was changed from installing and operating air compressors for RSS sump pumps in the 1998 amendment to monitoring, maintaining, and repowering the sump pumps.

The current basis for Task 11 was changed from the 1998 license amendment to combine the opening of the breakers for non-safety grade sump pumps into one action and to account for additional shine sources.

Table 2.10.1-3 presents the current licensing basis vital area access dose estimates and a description of the current actions.

The MPS3 design as related to both occupational and public radiation exposure was evaluated for continued acceptability to support license renewal. NUREG-1838, Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, dated August 1, 2005 documents the results of that review. NUREG-1838 Section 1.2.2 addresses the Environmental Review. There is no specific section in NUREG-1838 that discusses normal plant radiation levels, shielding adequacy, radiation monitoring setpoints, post-accident vital area accessibility, and occupational exposure.

2.10.1.2 Technical Evaluation

The technical evaluation is presented in six sub-sections as listed below:

- Normal Operation Radiation Levels and Shielding Adequacy
- Radiation Monitoring Setpoints
- Post Accident Vital Area Accessibility
- Normal Operation Radwaste Effluents and Annual Dose to the Public
- Ensuring that Occupational and Public Radiation Exposures are ALARA

- Evaluation of Impact on Renewed Plant Operating License Evaluations

2.10.1.2.1 Normal Operation Radiation Levels and Shielding Adequacy

2.10.1.2.1.1 Introduction

Cubicle wall thickness is specified not only for structural and separation requirements, but also, to provide radiation shielding in support of radiological equipment qualification, and to reduce operator exposure during all modes of plant operation, including maintenance and accidents.

Conservative estimates of the radiation sources in plant systems and personnel access requirements form the bases of normal operation plant shielding and radiation zoning. These radiation source terms are primarily derived from conservative estimates of the reactor core and reactor coolant (also called primary coolant) isotopic activity inventory and are referred to as “design basis” source terms. SPU will impact the isotopic activity inventory in the core. In addition, since the “design basis” reactor coolant source term is based on 1 percent fuel defects, the SPU will result in an increase in the “design basis” reactor coolant activity concentration.

The “expected” radiation source terms in the coolant will also be impacted by the SPU. “Expected” source terms are less than that allowable by the plant Technical Specifications and are usually significantly less than the “design basis” source terms.

The impact of the SPU on the normal operation dose rates and the adequacy of existing shielding are evaluated to ensure continued safe operation within applicable regulatory limits. The assessment is broken into two parts; the impact of SPU on a) plant radiation levels during normal operation, and b) adequacy of existing shielding for normal plant operation.

The shielding design basis for MPS3 is summarized in FSAR Section 12.3.1 with the radiation source terms summarized in FSAR Section 12.2. The original plant shielding design was based on a core power level of 3636 MWt and a one-year fuel cycle length. MPS3 is currently operating with an 18 month fuel cycle. The impact of the change in fuel cycle length on plant radiation levels is monitored, and operator exposure controlled, by the MPS3 Radiation Protection Program. The original design calculations supporting plant shielding remain adequate for current plant operations.

The SPU analysis is conservatively based on a core power level of 3723 MWt and an 18-month fuel cycle. An increase of fuel cycle length will increase the inventory of long-lived isotopes in the core and in the reactor coolant. The activity inventory of a few isotopes that are produced primarily by neutron activation of stable or long-lived fission products will also increase due to longer accumulation time.

The SPU requires an increase of the nuclear fission rate and consequently, an increase of neutron flux and the fission product generation rate. This leads to an increase of the fission product inventory in the core and spent fuel, and an increase of neutron and gamma flux leaking out of the reactor vessel.

The increase in the neutron flux results in an increase of neutron activation products in the reactor cooling system, control rod assemblies, reactor internals, and in the pressure vessel. The increase in the core inventory of fission products and actinides due to the SPU will also increase the activity concentrations in the reactor coolant due to fuel defects.

The activity concentrations in the secondary system will also increase due to primary-to-secondary leakage in the steam generators. The radiation source in the downstream systems will undergo a corresponding increase. This increase in the radioactivity levels, and the associated increase in the radiation source strength results in an increase of radiation levels in the Containment Building, Auxiliary Building, Engineered Safety Features Building, Main Steam Valve Building, Turbine Building, Fuel Building, and other locations, including offsite, which are subject to direct shine from radiation sources contained in these buildings.

2.10.1.2.1.2 Description of Analyses and Evaluations

The SPU evaluation utilizes scaling techniques to determine the impact of SPU on plant radiation levels. This evaluation takes credit for conservatism in existing shielding analyses and the site ALARA Program to demonstrate continued adequacy of current plant shielding to support compliance with the operator exposure limits of 10 CFR 20.

1. Normal Operation Radiation Levels

For the same source-shield-detector configuration, the dose rate at a given detector point is directly proportional to the radiation source strength in the source region. The impact of increasing the reactor power from the current licensed level of 3411 MWt to the conservatively analyzed core power level of 3723 MWt on the neutron flux and gamma flux in and around the core, fission product and actinide activity inventory in the core and spent fuels, N-16 source in the reactor coolant, neutron activation source in the vicinity of the reactor core, and fission/corrosion products activity in the reactor coolant and downstream systems, was examined, and the increase quantified. This flux or activity increase factor for a given radiation source was determined to be the SPU scaling factor for the expected dose rate due to that source.

The SPU assessment with regard to normal operation radiation levels is divided into four areas:

- Areas Near the Reactor Vessel

  During normal operation, the radiation source in the reactor core is made up of neutron and gamma fluxes that are approximately proportional to the core power level. The radiation sources during shutdown are the gamma fluxes in the core and the activation activities in the reactor internals, pressure vessel, and primary system piping walls, which also vary approximately in proportion to the reactor power.

  The radiation dose rate near the reactor vessel is determined by the leakage flux from the reactor vessel. Therefore, an uprate from the current licensed core power of 3411 MWt to an analyzed core power of 3723 MWt is expected to increase the normal operation radiation levels in areas near the reactor vessel by a factor of approximately 1.09, i.e., 3723/3411.

- In-Containment Areas Adjacent to the Reactor Coolant System

  During normal operation, the major radiation source in the reactor coolant system components located within containment is N-16. With the core power increase from 3411

MWt to the analyzed core power of 3723 MWt, the fast neutron flux is expected to increase by approximately 9 percent. The coolant residence time in the core and the transit time are not expected to change significantly due to uprate. Therefore, the SPU scaling factor for the areas subjected to the N-16 source is 1.09.

The deposited corrosion product activity depends on the reactor coolant chemistry and the cobalt impurity in reactor coolant system and steam generator components. Since the water chemistry remains approximately the same, and the SPU will increase the neutron flux by approximately 9 percent, the corrosion product activity deposits and the associated shutdown dose rate are also expected to increase by 9 percent.

- Areas Near Irradiated Fuels and Other Irradiated Objects

  These areas include the refueling canal, spent fuel pool, incore instrumentation drive assembly area, and other areas housing neutron irradiated materials. The radiation source is the gamma rays from the fission products and activation products, which are determined by the fission rate, neutron flux level and the irradiation time.

  Since both the fission products and the activation products are expected to increase by approximately 9 percent for a core power increase from 3411 MWt to the analyzed core power level of 3723 MWt, the SPU scaling factor for the areas subjected to irradiated fuels and other irradiated sources is 1.09.

- Areas outside Containment where the Radiation Source Is Derived from the Primary Coolant Activity

  In most areas outside the reactor containment, the radiation sources are either the primary coolant itself or down-stream sources originating from the primary coolant activity. Following SPU, both the fission products and the activated corrosion products in the primary coolant, and thus the down-stream sources, are expected to increase by approximately 9 percent for a core power increase from 3411 MWt to the analyzed power level of 3723 MWt.

  The SPU scaling factor for the areas outside containment where the radiation source is derived from the primary coolant activity is, in general, 1.09 with the exception of the area near the condensate polishing system. The radiation level near the condensate polishing system may increase slightly greater than the percentage of SPU due to the increased steam flow rate and moisture carryover fraction associated with SPU.

  An assessment of the impact of the SPU on the activity accumulation on the condensate polishers concludes that, due to the SPU, the long-lived non-particulate halogen isotopes in the condensate polishers, at steady state, will increase by an estimated value of 8 percent, due to the 1 percent decrease of halogen concentration in the steam generator liquid/steam and 9 percent increase of steam flow rate (i.e., 0.99 x 1.09). The long-lived particulate isotopes in the condensate polishers at steady state are estimated to increase by up to a factor of 5.34, due to an 8 percent decrease of particulate concentration in the steam generator liquid/steam, increase in the moisture carry-over fraction of 5.33, and 9 percent increase of steam flow rate (i.e., 0.92 x 5.33 x 1.09).

  For condensate polishers with fresh or newly regenerated resins, the activity is dominated by halogens and the radiation level for the same polisher operation time is estimated to increase by 8 percent. As the operation time increases, the contribution by the particulates will increase and the SPU impact will increase accordingly. However, this additional increase is limited because most of the particulates are removed by blowdown, and the particulate concentrations in the steam are many orders of magnitude less than those of halogens. Based on the above, it can be concluded that the dose rates near the condensate polishers increase by approximately the same percentage as the SPU or slightly higher.

2. Plant Shielding Adequacy

Shielding is used to reduce radiation dose rates in various parts of the station to acceptable levels consistent with operational and maintenance requirements and to maintain the dose rates at the site boundary to below those allowed for continuous non-occupational exposure.

The original MPS3 shielding design was based on plant operation at a core power level of 3636 MWt/12 month fuel cycle, upon generalized occupancy requirements in various radiation zones of the station, and upon conservative reactor coolant source terms assuming 1 percent fuel defects.

The SPU evaluation takes into consideration that the occupancy requirements are not affected by SPU. Similarly, the layout/configuration of systems containing radioactivity are unchanged by the SPU. Consequently, the SPU evaluation focused on determining an SPU scaling factor based on the design basis fission and corrosion product activity concentrations in the reactor coolant used in the original plant shielding design as documented in FSAR Table 11.1-2, and the corresponding SPU design basis reactor coolant activity concentrations presented in Table 2.10.1-1 which reflects an analyzed core power level of 3723 MWt, an 18-month fuel cycle length, 1 percent fuel defects and reduced use of the cation bed demineralizers than assumed during original design. In accordance with current licensing basis, computer code ACTIVITY2 is used to calculate the design basis primary coolant activity concentrations for MPS3 at SPU conditions. Note that the design basis SPU core inventory was calculated by the industry computer code ORIGEN. Consequently, the primary coolant activity concentrations calculated by the ACTIVITY2 code are adjusted by the ratio of the ORIGEN core inventory to the core inventory calculated by ACTIVITY2. This approach is acceptable because the source of primary coolant fission product activity is the leakage of core activity via the defective fuels.

The source terms at the analyzed power are compared to the source terms used in the original shielding design to evaluate the adequacy of the shielding design. The SPU evaluation takes into consideration a) the conservative analytical techniques used to establish plant shielding design, b) the Technical Specification limits on the reactor coolant activity concentrations, and c) the station ALARA program which minimizes the radiation exposure to plant personnel.

1. Primary Shielding

As discussed in FSAR 12.3.1.1, the primary shield consists of a water-filled neutron shield tank and a reinforced concrete structure that surrounds the reactor vessel. The primary function of the primary shield is to attenuate the neutron and gamma fluxes leaking out of the reactor vessel. Fuel cycle length has insignificant impact on the maximum dose rates around the reactor vessel which are based on the neutron and gamma flux during power operation.

DNC reviewed the fluence calculations and confirmed that the original design calculations remain bounding for SPU conditions. With continued use of low leakage fuel management following SPU, the existing primary shielding remains adequate, and the estimated dose rates adjacent to the reactor vessel/primary wall remain within original design.

2. Secondary Shielding

As discussed in FSAR Section 12.3.1.2, the secondary shield consists of the reactor coolant loop shielding, containment structure shielding, fuel handling shielding, auxiliary equipment, radwaste storage shielding, etc.

- The reactor coolant loop shielding and the containment are reinforced-concrete structures that surround the reactor coolant system and the steam generators. The primary function of these secondary shields is to attenuate the N-16 source, which emits high-energy gammas. These shields were designed to limit the full power dose rate outside the containment building to acceptable levels. The N-16 source is expected to increase by approximately 2.5 percent (i.e., 3723/3636). The N-16 activity level is not impacted by fuel cycle length. The impact of the estimated 2.5 percent increase in source terms is bounded by the conservative analytical techniques used to establish plant shielding design (such as ignoring the shadow shielding effect of the neighboring sources, rounding up the calculated shield thickness to a higher whole number, and using a conservative infinite medium build-up factor), and the current reactor coolant loop shielding and containment structure is determined to be adequate for continued safe operation following SPU.

- The fuel handling shielding provides protection during all phases of removal and storage of spent fuel and control rods. The fuel handling shield was designed to insure a dose rate of <0.75 mrem/hr outside the fuel building, and <2.5 mrem/hr in the fuel building and in the adjacent auxiliary building from the fuel stored in the spent fuel pool.

  With the analyzed core power increase from 3636 MWt to 3723 MWt, the gamma source from the irradiated fuel is estimated to increase by approximately 2.5 percent. The 18-month fuel cycle will also increase the inventory of long-lived isotopes in the irradiated fuel. However, this is not a significant concern as the dose rates near the refueling canal and the spent fuel pool are dominated by the shorter half-life isotopes in the freshly discharged spent fuel assemblies. The impact of the estimated 2.5 percent increase in source terms used in the SPU analysis vs. the original shielding analysis is bounded by the conservative analytical techniques discussed earlier, which were used to establish plant shielding design. Consequently, the current spent fuel shielding is determined adequate for continued safe operation following SPU.

- Regarding the shielding provided outside the containment where the radiation sources are either the reactor coolant itself or down-stream sources originating from coolant activity, a review was performed of the SPU design primary coolant source terms (fission and activation products) vs. the original design basis primary coolant source terms. It is noted that the analyzed design primary coolant source terms utilized for the SPU reflect a core power level of 3723 MWt, operation with an 18-month fuel cycle, one percent fuel defects, reduced use of the cation bed demineralizers, and more advanced fuel burn-up modeling/libraries as compared to the computer codes used in the original analyses which addressed a core power level of 3636 MWt and a one-year fuel cycle length.

The SPU assessment concluded that the estimated increase in the dose rate for shielded configurations based on the design SPU reactor coolant versus the pre-uprate coolant is compensated by the plant technical specifications which will limit the SPU RCS, degassed RCS, and RCS noble gas source terms and associated dose rates to less than the original design basis values. It is therefore concluded that the shielding design based on the original design basis primary coolant activity remains valid for the SPU condition.

2.10.1.2.1.3 Results

The normal operation radiation levels in most of the plant areas are expected to increase by approximately 9 percent, i.e., the percentage increase between the current licensed power level of 3411 MWt, and the conservatively analyzed core power level of 3723 MWt used for the SPU assessment. The exposure to plant personnel and to the offsite public is also expected to increase by the same percentage.

The increase in expected radiation levels will not affect radiation zoning or shielding requirements in the various areas of the plant. This is because the increase is offset by the:

1. conservative analytical techniques typically used to establish shielding requirements,
2. conservatism in the original “design basis” reactor coolant source terms used to establish the radiation zones, and
3. Plant Technical Specification Section 3.4.8 which limits the reactor coolant concentrations to levels at or below the original design basis source terms.

As indicated in FSAR Sections 12.1 and 12.5, individual worker exposures will be maintained within the regulatory limits of 10 CFR 20 for occupational exposure by the site ALARA program that controls access to radiation areas. In addition, the Offsite Dose Calculation Manual ensures that the radiation levels at the site boundary due to direct shine from radiation sources in the plant will be maintained within the regulatory limits of 10 CFR 20 and 40 CFR 190 for continuous non-occupational exposure.

The SPU assessment also demonstrates continued compliance with GDC-19 with regard to radiation protection, insofar that actions can continue to be taken in the control room to operate the nuclear power unit safely during normal operation.

2.10.1.2.2 Radiation Monitoring Setpoints

2.10.1.2.2.1 Introduction

The function of area monitor alarm setpoints is to provide an early warning of changing radiological conditions in a specified area. The function of alarm setpoints for process/effluent monitors is to indicate leakage or malfunction of equipment, or a potential for an activity release that may exceed the release rate limit. The high alarm setpoint of many liquid effluent monitors will initiate interlocks that terminate activity release to the environment. The function of the post-accident radiation monitors is to give notice of significant radiation levels within plant areas or in environmental releases from the plant.

SPU will increase the activity level of radioactive isotopes which will result in an increase of radiation levels in various plant areas and potentially increase the radioactive environmental releases from the plant.

2.10.1.2.2.2 Description of Analyses and Evaluations

The SPU evaluation examined the impact of increased radioactivity levels in the monitored streams/areas, and the associated background radiation levels, to assess the applicability of the current radiation monitor setpoint basis/values following SPU.

As discussed earlier, the SPU will increase the activity level of radioactive isotopes in most streams/components and the associated radiation levels by approximately the percentage of the core power uprate. The relative isotopic compositions in the process and effluent streams are not expected to change due to SPU.

The bases of the radiation monitor setpoints at MPS3 are either a regulatory commitment (i.e., the definition of a high radiation zone, or radioactivity in environmental releases that are fractions or multiples of the release rate or dose limits and are intended to give notice of releases approaching the limits in 10 CFR 20 or 10 CFR 50, Appendix I), a multiple of the background, or an elevated value indicating an unusual event (such as leakage or malfunction of systems), that leads to a sudden increase of the activity level in the monitored stream. The setpoint bases are not power level dependent, and the setpoint values are established using plant operating data and are reviewed and adjusted as required.

2.10.1.2.2.3 Results

The SPU evaluation determined that all of the radiation monitor setpoint bases, and the methods of setpoint determination, continue to be valid following SPU.

2.10.1.2.3 Post Accident Vital Area Accessibility

2.10.1.2.3.1 Introduction

In accordance with Revision 2 of NUREG-0737, II.B.2, and its predecessor NUREG-0578, Item 2.1.6.b, vital areas are those areas within the station that will or may require access/occupancy to support accident mitigation following a loss of coolant accident (LOCA). In accordance with the above regulatory document, all vital areas and access routes to vital areas must be designed such that operator exposure while performing vital access functions remain within regulatory limits.

This section focuses on areas that may require short-term, one-time or infrequent access following a LOCA. On-site locations that require continuous occupancy and a demonstration of 30-day habitability are addressed in Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms.

A review of the Emergency Operating Procedures and changes to the design basis accident analysis for the SPU resulted in several of the vital area access requirements being no longer required or being completed in low dose areas. Task 9, 11 and 12 are in this category.

Due to the change in the RWST shine component described below, Task 10 has been changed from monitoring, maintaining, and repowering the sump pumps to repowering the sump pumps. The completion time for this activity was changed to 2 to 6 hours. The task was also split into two parts. One part is completed in the ESF building (manipulate the MCC for the pump) and the other part is completed in the ESF yard north of the RWST (repower the pump).

Due to a conservative modeling change related to the SPU LOCA RWST release and an increase in the allowable RWST backleakage related to the AST implementation, the concentration of radionuclides in the RWST has increased significantly since the 1998 License Amendment. Several of the alternate routes pass close to the RWST and part of Task 10 is completed in the yard next to the RWST. The RWST shine component has been revised for Task 10 and the alternate routes for transit to Tasks 3, 10, and 13. This RWST shine component includes the uprated core inventory and uses the flow rate timing discussed in the LOCA analysis, but assumes a TID-14844 sump inventory at the initiation of the event.

Core power uprate will typically increase the activity level in the core by the percentage of the uprate. The radiation source terms in equipment/structures containing post-accident fluids, and the corresponding environmental radiation levels, will increase proportionately to the uprate. In addition, factors that impact the equilibrium core inventory, and consequently the estimated radiation environment, are fuel enrichment and burnup. These additional changes could result in activity levels in the core that are typically higher than the core power ratio associated with the uprate.

As discussed earlier, MPS3 has been approved for use of Alternative Source Terms as outlined in 10 CFR 50.67, SRP 15.0.1 and RG 1.183 for post-accident dose assessments associated with the site boundary and on-site locations that require continuous occupancy such as the Control Room. However, for the reasons summarized in SECY-98-154, “Results of the Revised (NUREG-1465) Source Term Rebaselining of Operating Reactors,” dated June 30, 1998, the SPU assessment, for purposes of evaluating the impact on operator exposure while performing vital functions in areas that require infrequent access, is based on TID 14844, “Calculation of Distance Factors for Power and Test Reactors”, dated 1962, source terms. The alternative source term benchmarking study reported in SECY-98-154 concluded that results of analyses based on TID 14844 would be more limiting earlier in the event, after which time the alternative source term results would be more limiting. Post-LOCA access to vital areas for purposes of accident mitigation and safe shutdown occurs earlier on in the event when the original TID 14844 source term is more limiting.

2.10.1.2.3.2 Description of Analyses and Evaluations

The SPU assessment is based on an analyzed core power level of 3723 MWt (3650 MWt plus 2 percent calorimetric uncertainty) and an 18-month fuel cycle. The methodology utilized in the SPU evaluation is to demonstrate; using scaling techniques, continued compliance with the operator exposure dose limits of 5 rem provided in Revision 2 of NUREG-0737, II.B.2 and its predecessor NUREG-0578, item 2.1.6.b. MPS3 currently operates at a licensed power level of

3411 MWt with 18 month fuel cycles. However, the analyses of record supporting the accident radiological environmental qualification are based on a core power level of 3636 MWt (3565 MWt plus 2 percent uncertainty) and a 12 month fuel cycle.

2.10.1.2.3.3 Scaling Evaluation

The impact of the SPU on the post-LOCA gamma radiation dose rates developed in the 1998 License Amendment and utilized to determine operator exposure during vital area access is evaluated by comparing the gamma source terms, based on the original core inventory used to develop the post-LOCA dose rates, to the gamma source terms, based on the SPU core inventory. This approach takes into consideration that a) the post-LOCA operator mission requirements, including the task description and required time/duration for access is not impacted by the SPU, and b) SPU does not impact the operation and layout/arrangement of plant radioactive systems.

Theoretically, following SPU, the post-LOCA environmental gamma dose rates and the operator dose per identified mission should increase by approximately 7 percent (3650 MWt/3411 MWt). However, because the SPU analyzed core reflects: a) only a 2.4 percent (3723 MWt/3636 MWt) power increase over the previous vital area access analysis, b) includes operation with an 18 month fuel cycle versus 12 months in the previous vital area access analysis, and c) more advanced fuel burnup modeling/libraries than used in the 1998 vital area access analyses; the calculated SPU scaling factor values deviate from the core power ratio.

The SPU assessment is essentially a two-step process. The first develops a bounding SPU dose rate scaling factor vs. time, and the second multiplies the pre-SPU personnel dose/dose rates at task locations identified in the licensing basis by the bounding SPU scaling factor.

The pre-SPU and the SPU core inventories are utilized to develop the post-LOCA gamma energy release rates (Mev/sec) per energy group vs. time for containment atmosphere, sump water and pressurized recirculating fluid.

For the “unshielded” case, the factor impact on post-accident gamma dose rates is estimated by rationing the gamma energy release rates weighted by dose rates, as a function of time, for the SPU analyzed core power level, to the corresponding weighted source terms based on the pre-SPU analyzed core power level. To address the fact that the vital access locations are outside containment, the “unshielded” values include the shielding effect of a pipe wall thickness associated with a 2-inch nominal diameter pipe. This ensures that the results are not skewed by photons at energies less than 25 keV, which will be substantially attenuated by any piping sources.

To evaluate the scaling factor impact of the SPU on post-LOCA gamma dose rates (vs. time) in areas that are “shielded”, the pre-SPU as well as the SPU source terms discussed above were weighted by the concrete reduction factors for each energy group. The concrete reduction factors for 1 and 3 feet of concrete are used to provide a basis for comparison of the post-LOCA spectrum hardness of source terms, with respect to time, for both original design and SPU cases, for lightly shielded and heavily shielded cases.

The SPU gamma dose rate scaling factors vary with source, time, as well as shielding. Scaling factors determined by the assessments described above ranged from a low of 0.89 to high of 1.22. To cover all types of analysis models/assessments, the maximum dose rate scaling factor with respect to time and source developed from the above assessments was used for each source/receptor combination, with or without shields, for the time period identified in the vital access assessment. For simplicity, Tasks 1, 3, and 4 just used the scaling factor of 1.22. The remainder of the tasks used a combination of time and source dependent scaling factors between 0.89 and 1.22, which were appropriate for the time and specific nature of the individual task.

2.10.1.2.3.4 Access Routes to Task Locations and Completion Times

The planned access routes to the task areas have not changed from the 1998 License Amendment. Travel times used in the 1998 License Amendment have been assessed for the SPU in consideration of the addition of locked security gates around the site and have been determined to be adequate.

Completion times, with the exception of Task 10, have not changed from the 1998 License Amendment. As mentioned above, Task 10 will be completed in the 2 to 6 hour period. Previously, Task 10 was accomplished in the 8 to 24 hour period with additional evaluations for the 1 to 4 and 4 to 30 day periods.

2.10.1.2.3.5 Results

Table 2.10.1-4 presents the vital area access dose estimates following the SPU. The table demonstrates that the SPU post-LOCA vital area operator dose estimates remain within the regulatory limit of 5 Rem whole body listed in NUREG-0737, II.B.2.

2.10.1.2.4 Normal Operation Radwaste Effluents and Annual Dose to the Public

2.10.1.2.4.1 Introduction

Liquid and gaseous effluents released to the environment during normal plant operations contain small quantities of radioactive materials.

Liquid, gaseous and solid radwaste systems are designed such that the plant is capable of maintaining normal operation offsite gaseous and liquid releases and doses within regulatory limits. The actual performance and operation of installed equipment, as well as reporting of actual offsite releases and doses, is controlled by the requirements of the Offsite Dose Calculation Manual (ODCM).

There are no specific regulatory limits associated with generation of solid radwaste other than those associated with transportation. However, onsite storage of radwaste may result in increased public exposure at the site boundary which is controlled by federal regulations.

Core power uprate will increase the activity level of radioactive isotopes in the reactor and secondary coolant and steam. Due to leakage or process operations, fractions of these fluids are transported to the liquid and gaseous radwaste systems where they are held prior to discharge. As the activity levels in the coolants and steam are increased, the activity level of radwaste inputs, and subsequent environmental releases, are proportionately increased.

2.10.1.2.4.2 Description of Analyses and Evaluations

The methodology used in the SPU evaluation is to demonstrate, using scaling techniques, continued compliance with the annual dose limits to an individual in an unrestricted area set by 10 CFR 20, 10 CFR 50, Appendix I and 40 CFR 190 resulting from radioactive gaseous and liquid effluents released to the environment following SPU. Note that limits on dose to the public resulting from normal operation are addressed in 10 CFR 20, 10 CFR 50 Appendix I as well as 40 CFR 190; however, 10 CFR 50 Appendix I which is based on the concept of “as Low As Reasonably Achievable” is the most limiting. 10 CFR 20 does have a release rate criteria that does not exist in 10 CFR 50 Appendix I, but the ODCM controls actual performance and operation of installed equipment and releases, thus maintaining compliance with that aspect of 10 CFR 20. In addition, if the projected increase in offsite doses due to radioactive gaseous and liquid effluents either approach or exceed 10 CFR 50, Appendix I guidelines, then the methodology in the ODCM is utilized to determine continued compliance with 40 CFR 190. Per Section IV.E of the ODCM, compliance with the limits of 40 CFR 190 needs to be addressed if the calculated doses from gaseous or liquid radwaste effluents exceed the limits imposed by 10 CFR 50 Appendix I by a factor of 2.

There are no changes as a result of the SPU to existing radioactive waste systems (gaseous and liquid) design, plant operating procedures or waste inputs as defined by NUREG-0017, Revision 1. Therefore, a comparison of releases can be made based on current vs. SPU inventories/radioactivity concentrations in the reactor coolant and secondary coolant/steam. As a result, the impact of the SPU on radwaste releases and Appendix I doses can be estimated using scaling techniques.

Scaling techniques based on NUREG-0017, Revision 1 methodology were utilized to assess the impact of SPU on radioactive gaseous and liquid effluents at MPS3. Use of the adjustment factors presented in NUREG-0017, Revision 1 allows development of coolant activity scaling factors to address SPU.

The SPU analysis utilized the plant core power operating history during the years 2001 to 2005, the reported gaseous and liquid effluent and dose data during that period, NUREG-0017, Revision 1, equations and assumptions and conservative methodology to estimate the impact of operation at the analyzed SPU core power level. The results were then compared to the comparable data from current operation on radioactive gaseous and liquid effluents and the consequent normal operation off-site doses.

The licensed reactor core power level during the 2001 to 2005 time frame was 3411 MWt. For the SPU condition, the system parameters utilized in the SPU analysis reflected the flow rates and coolant masses at an analyzed NSSS power level of 3666 MWt and a core power level of 3723 MWt, which includes a 2 percent margin for power uncertainty. For the current condition, the evaluation utilized offsite doses based on an average 5 year set of organ and whole body doses calculated from effluent reports for the years 2001 through 2005 including the associated average annual core power level extrapolated to 100 percent availability at the licensed power level.

Using the methodology and equations found in NUREG-0017, Revision 1, and based on a comparison of the change in power level and in plant coolant system parameters (e.g., reactor coolant mass, steam generator liquid mass, steam flow rate, reactor coolant letdown flow rate, flow rate to the cation demineralizer, letdown flow rate for boron control, steam generator blowdown flow rate, steam generator moisture carryover, etc.) for both current and SPU conditions, the maximum potential percentage increase in coolant activity levels due to the SPU, for each chemical group identified in NUREG-0017, was estimated. To estimate an upper bound impact on off-site doses, the highest factor found for representative isotopes in any chemical group (including corrosion products), pertinent to the release pathway was applied to the average doses previously determined as representative of operation at current conditions. This approach was utilized to estimate the maximum potential increase in effluent doses due to the SPU and to demonstrate that the estimated off-site doses following SPU, although increased, will continue to remain below the regulatory limits.

The impact of SPU on solid radwaste generation was qualitatively addressed based on NUREG-0017, Revision 1, methodology, engineering judgment and the understanding of radwaste and affected plant system operation on the generation of solid radwaste.

The analysis concluded the following:

1. Expected Reactor Coolant Source Terms

Based on a comparison of current vs. SPU input parameters, and the methodology outlined in NUREG-0017, Revision 1, the maximum expected increase in the reactor coolant source is approximately 9.5 percent for noble gases and 9.1 percent for long half-life activity. The above change is primarily due to the estimated decrease in RCS mass (~0.3 percent) and increase in effective core power level (~9.1 percent, i.e., 3723 MWt [uprate power level including 2 percent instrument uncertainty]/3411 MWt pre-uprate licensed power level) between current and SPU conditions. Considering the accuracy and error bounds of the operational data utilized in NUREG-0017, Revision 1, this percentage is well within the uncertainty of the existing NUREG-0017, Revision 1 based expected reactor coolant isotopic inventory used for radwaste effluent analyses.

2. Liquid Effluents

As discussed above, there is a maximum 9.1 percent increase in the radioactivity content of the liquid releases since input activities are based on long-term reactor coolant activity which is proportional to the SPU percentage increase, and on waste volumes which are essentially independent of power level within the applicability range of NUREG-0017. Tritium releases in liquid effluents are assumed to increase approximately 9.1 percent (corresponding to the effective core power uprate percentage) since the analysis is based on changes in an existing facility's power rating without changing its mode of operation.

3. Gaseous Effluents

For all noble gases, there will be a bounding maximum 9.5 percent increase of radioactivity content in effluent releases due to the effective core power uprate percentage increase and decrease in primary coolant mass.

Tritium releases in the gaseous effluents increase in proportion to their increased production (9.1 percent), which is directly related to core power and is allocated in this analysis in the same ratio as current releases.

The impact of the SPU on iodine releases is approximated by the effective power level increase with the calculated increase in the reactor coolant I-131 of 9.2 percent.

For particulates, the methodology of NUREG-0017 specifies the release rate per year per unit per building ventilation system. This is not dependent on power level within the range of applicability. Particulates released via the turbine building due to leakage of main steam and air ejector exhaust are generally considered to be a small fraction of total particulate releases. Thus, minimal change would be expected for the SPU operations. However, a conservative approach is dictated by the fact that the annual effluent release reports do not delineate the “source” of particulates or iodines released. In addition at MPS3, tritium is included in the category with iodines and particulates (radionuclides with half-lives greater than 8 days).

On the secondary side, moisture carryover is a major factor in determining the non-volatile activity in the steam. The multiplier applicable to the particulates released via the turbine building due to main steam leaks and air ejector exhaust is higher than the percentage of the SPU (primarily due to a conservatively estimated 5.3 fold increase in moisture carryover due to the SPU, coupled with a 9.1 percent increase in coolant concentration). However the contribution of particulates to the “Iodine and Particulate” category was insignificant compared to the dose contribution from tritium. Thus the scaling factor for the entire “particulate and iodine” category was conservatively estimated at 9.1 percent.

4. Estimated Impact on Effluent Doses

Table 2.10.1-2 shows that, based on operating history, the maximum estimated dose due to liquid and gaseous radwaste effluents following SPU is significantly below the 10 CFR 50, Appendix I limits.

5. Solid Radioactive Waste

For MPS3, the volume of solid waste would not be expected to increase proportionally because the power uprate neither appreciably impacts installed equipment performance, nor does it require drastic changes in system operation or maintenance. Only minor, if any, changes in waste generation volume are expected. However, it is estimated that the activity levels for most of the solid waste would increase proportionately to the increase in long half-life coolant activity bounded by the 9.1 percent maximum increase.

Taking into consideration the average capacity factor during the five year evaluation period of 0.8902, the total long-lived activity contained in the waste following SPU is estimated to be bounded by approximately 10.22 percent (i.e., 9.1 percent/0.8902) over that currently stored on site.

In the long term, the direct shine dose due to radwaste stored on site could be conservatively estimated to increase by approximately 10.22 percent as a) current waste decays and its contribution decreases, b) the radwaste is routinely moved offsite for disposal, c) waste generated post-uprate enters into storage and d) plant capacity factor approaches the target of 1.0.

As the impact on direct shine doses is cumulative from wastes generated from all units onsite over the plants' lifetime and stored onsite, procedures and controls in the ODCM monitor and control this component of the off-site dose and would limit, through administrative and storage controls, the offsite dose to ensure compliance with the 40 CFR 190 direct shine dose limits.

6. Impact of SPU on Direct Shine

The discussion below regarding compliance with 40 CFR 190 is provided for completeness even though per the ODCM, demonstration of compliance with 40 CFR 190 is not required unless the dose limits of 10 CFR 50 Appendix I are exceeded by a factor of 2. Table 2.10.1-2 demonstrates that the SPU dose estimates are well below the design objectives of 10 CFR 50, Appendix I.

The 40 CFR 190 whole body dose limit of 25 mrem to any member of the public includes a) contributions from direct radiation (including skyshine) from contained radioactive sources within the facility, b) the whole body dose from liquid release pathways, and c) the whole body dose to an individual via airborne pathways.

The current annual direct shine dose ranged from 0.140 mrem to 0.120 mrem (average is 0.13 mrem) during the 2-year period evaluated (methodology to calculate the direct shine dose was revised to incorporate a more conservative approach for the 2004 and 2005 reports used in the evaluation), as compared to the regulatory limit established by 40 CFR 190 which is 25 mrem/yr. Consequently, the current annual whole body dose from all pathways due to liquid releases, gaseous releases and direct shine during the period evaluated is conservatively estimated at 0.15 mrem (i.e., 0.0024 +0.0185 +0.13).

The direct shine dose due to plant operation would increase by the increase percentage of the power level, i.e., 9.1 percent, however, as discussed above, the direct shine contribution due to accumulation of stored solid radwaste, could increase by approximately 10.22 percent following SPU. The bounding scaling factor of 10.22 percent is conservatively used to estimate the SPU direct shine dose; i.e., 0.13 mrem X 1.1022 = 0.1433 mrem. Consequently, the current annual whole body dose from all pathways due to liquid releases, gaseous releases and direct shine is conservatively estimated at 0.17 mrem (i.e., 0.0026 + 0.0203 + 0.1433), which remains within the 40 CFR 190 whole body dose limit of 25 mrem to any member of the public

2.10.1.2.4.3 Results

DNC is required to meet the requirements of 40 CFR 190, 10 CFR 20 and 10 CFR 50, Appendix I. However, 10 CFR 50 Appendix I is the most limiting.

10 CFR 20 does have a release rate criteria that does not exist in 10 CFR 50 Appendix I, but the plant Technical Specifications and the Offsite Dose Calculation Manual control actual performance and operation of installed equipment and releases thus maintaining compliance with that aspect of 10 CFR 20.

If the normal operation doses due to radioactive gaseous and liquid effluents either approach or exceed 10 CFR 50, Appendix I guidelines, then the Technical Specifications and the Offsite Dose Calculation Manual ensure continued compliance with 40 CFR 190.

The SPU has no significant impact on the expected annual radwaste effluent doses (i.e., this analysis demonstrates that the estimated doses following SPU will remain a small percentage of allowable Appendix I doses - see Table 2.10.1-2). It is therefore concluded that following SPU, the liquid and gaseous radwaste effluent treatment systems, in conjunction with the procedures and controls provided by the Offsite Dose Calculation Manual, will remain capable of maintaining normal operation offsite doses within the regulatory requirements.

2.10.1.2.5 Ensuring that Occupational and Public Radiation Exposures Are ALARA

2.10.1.2.5.1 Introduction

As discussed in FSAR Section 12.1, it is DNC policy to implement a program that meets the requirements of 10 CFR 20 and ensures that the occupational radiation exposures at its nuclear facilities are kept ALARA.

Implementation of the overall requirements of 10 CFR 50, Appendix I relative to utilization of radwaste treatment equipment to ensure that radioactive discharges and public exposure are ALARA are formalized in the Technical Specification requirements for the Radioactive Effluent Controls Program and the Offsite Dose Calculation Manual.

2.10.1.2.5.2 Description of Analyses and Evaluations

As noted in FSAR Section 12.1, ALARA procedures currently in place govern all activities in restricted areas at MPS3. Design features credited to support MPS3's commitment to ALARA operator exposures include shielding which is provided to reduce levels of radiation, ventilation which is arranged to control the flow of potentially contaminated air, an installed radiation monitoring system which is used to measure levels of radiation in potentially occupied areas and measure airborne radioactivity throughout the plant and respiratory protective equipment which is used as prescribed by the Radiation Protection Program.

Compliance with the requirements of the Offsite Dose Calculation Manual ensures that radioactive discharges and public exposure are ALARA.

The SPU assessments documented in Section 2.10.1.2.1 through 2.10.1.2.4 demonstrate that the dose limits imposed by regulatory requirements are met following SPU. The SPU does not impact the effectiveness of the design features credited to support DNC commitment to ALARA operator exposures. The intent of the ALARA procedures remain unchanged, specifically, a) the allowable limits on operator and public exposure and b) the intent to keep operator and public exposure at a minimum.

2.10.1.2.5.3 Results

It is concluded that no additional steps are necessary to ensure that dose increases are maintained ALARA.

2.10.1.2.6 Impact on Renewed Plant Operating License Evaluations

DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal application as related to normal plant radiation levels, shielding adequacy, radiation monitoring setpoints, post-accident vital area accessibility, and normal operation radwaste effluents. As stated in Section 2.10.1.1 the environmental review is within the scope of License Renewal but normal plant radiation levels, shielding adequacy, radiation monitoring setpoints, post-accident vital area accessibility, and occupational exposure is not addressed. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. The SPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.10.1.3 Conclusion

DNC has assessed the effects of the proposed SPU on radiation source terms and plant radiation levels and associated impact on shielding adequacy, radiation monitoring setpoints, post-accident vital area accessibility and normal operation radwaste effluents. DNC concludes that the evaluation adequately accounts for the effects of the proposed SPU on occupational and public radiation doses such that no additional steps are required to ensure that radiation doses will be maintained ALARA. Based on this, DNC concludes that the occupational and public radiation dose controls will continue to meet the MPS3 current licensing basis with respect to the requirements of GDC-19; 10 CFR 20; 10 CFR 50, Appendix I; 40 CFR 190 and NUREG-0737, II.B.2. DNC finds the proposed SPU is acceptable with respect to radiation protection and ensuring that occupational and public radiation exposures will be maintained ALARA.

Table 2.10.1-1
MPS3 SPU Design Reactor Coolant Activity Concentrations @ 3723 MWt

Nuclide	Primary Coolant Activity Conc. (μCi/g)	Nuclide	Primary Coolant Activity Conc. (μCi/g)	Nuclide	Primary Coolant Activity Conc. (μCi/g)	Nuclide	Primary Coolant Activity Conc. (μCi/g)
Kr 83m	3.53E-01	Rb 91	5.70E-03	Rh105m	3.82E-05	Ba139	7.79E-02
Kr 85m	1.09E+00	Rb 92	3.88E-04	Rh105	3.44E-04	Ba140	3.75E-03
Kr 85	1.33E-01	Sr 89	3.02E-03	Rh106	2.25E-04	Ba141	1.21E-04
Kr 87	8.49E-01	Sr 90	1.96E-04	Rh107	1.14E-05	Ba142	1.66E-04
Kr 88	2.22E+00	Sr 91	1.30E-03	Sn127	2.41E-06	La140	1.26E-03
Kr 89	6.96E-02	Sr 92	9.45E-04	Sn128	5.04E-06	La141	2.61E-04
Xe131m	1.93E-01	Sr 93	4.41E-05	Sn130	8.31E-07	La142	2.44E-04
Xe133m	7.68E-01	Sr 94	7.49E-06	Sb127	2.77E-05	La143	1.38E-05
Xe133	2.54E+01	Y 90	3.84E-04	Sb128	2.66E-06	Ce141	5.65E-04
Xe135m	9.45E-01	Y 91m	7.77E-04	Sb129	3.73E-05	Ce143	4.19E-04
Xe135	5.50E+00	Y 91	1.43E-02	Sb130	2.67E-06	Ce144	4.46E-04
Xe137	1.94E-01	Y 92	1.12E-03	Sb131	1.16E-05	Ce145	2.09E-06
Xe138	6.54E-01	Y 93	6.13E-04	Sb132	8.85E-07	Ce146	7.74E-06
		Y 94	2.72E-05	Sb133	1.04E-06	Pr143	5.20E-04
Br 83	7.05E-02	Y 95	1.14E-05	Te125m	3.98E-04	Pr144	4.50E-04
Br 84	3.50E-02	Zr 95	5.72E-04	Te127m	3.11E-03	Pr145	1.49E-04
Br 85	3.68E-03	Zr 97	3.67E-04	Te127	1.10E-02	Pr146	2.04E-05
Br 87	1.89E-03	Nb 95m	6.58E-06	Te129m	1.32E-02	Nd147	2.22E-04
I129	1.79E-07	Nb 95	5.78E-04	Te129	1.35E-02	Nd149	2.28E-05
I130	4.39E-02	Nb 97m	3.48E-04	Te131m	3.34E-02	Nd151	1.66E-06
I131	2.67E+00	Nb 97	3.91E-04	Te131	1.26E-02	Pm147	1.13E-04
I132	1.09E+00	Mo 99	5.27E+00	Te132	2.77E-01	Pm149	1.97E-04
I133	4.06E+00	Mo101	2.10E-02	Te133m	1.91E-02	Pm151	5.48E-05
I134	6.19E-01	Mo102	1.52E-02	Te133	8.60E-03	Sm151	7.50E-07
I135	2.39E+00	Mo105	7.22E-04	Te134	2.91E-02	Sm153	1.55E-04
I136	6.73E-03	Tc 99m	2.73E+00	Cs134m	4.72E-02		
		Tc101	2.05E-02	Cs134	2.31E+01	Cr 51	2.00E-03
Se 81	5.84E-07	Tc102	1.53E-02	Cs136	3.52E+00	Mn 54	3.30E-04

Table 2.10.1-1
MPS3 SPU Design Reactor Coolant Activity Concentrations @ 3723 MWt

Nuclide	Primary Coolant Activity Conc. (μCi/g)	Nuclide	Primary Coolant Activity Conc. (μCi/g)	Nuclide	Primary Coolant Activity Conc. (μCi/g)	Nuclide	Primary Coolant Activity Conc. (μCi/g)
Se 83	7.94E-07	Tc105	7.66E-04	Cs137	1.62E+01	Fe 55	1.70E-03
Se 84	4.60E-07	Ru103	5.49E-04	Cs138	1.00E+00	Fe 59	1.10E-03
Rb 86	1.46E-01	Ru105	1.34E-04	Cs139	8.99E-02	Co 58	1.70E-02
Rb 88	2.32E+00	Ru106	2.02E-04	Cs140	9.09E-03	Co 60	2.10E-03
Rb 89	1.45E-01	Ru107	1.90E-06	Cs142	1.08E-04	Np239	1.98E-02
Rb 90	1.12E-02	Rh103m	5.50E-04	Ba137m	1.52E+01		
						H-3	3.5E+00

Table 2.10.1-2
Estimated Annual SPU Doses to the Public
Normal Operation Gaseous and Liquid Radwaste Effluents

Type of Dose	Appendix I Design Objectives	100% Capacity Current case	Scaled Doses SPU Case	Percentage of Appendix I Design Objectives for SPU Case
Liquid Effluents				
Dose to total body from all pathways	3 mrem/yr	2.39E-03 mrem/yr	2.61E-03 mrem/yr	0.087%
Dose to any organ from all pathways	10 mrem/yr	1.15E-02 mrem/yr	1.26E-02 mrem/yr	0.126%
Gaseous Effluents				
Gamma Dose in Air	10 mrad/yr	2.04E-04 mrad/yr	2.23E-04 mrad/yr	2.23E-03%
Beta Dose in Air	20 mrad/yr	2.49E-04 mrad/yr	2.73E-04 mrad/yr	1.37E-03%
Dose to total body of an individual	5 mrem/yr	1.85E-02 mrem/yr	2.03E-02 mrem/yr	0.406%
Dose to skin of an individual	15 mrem/yr	1.93E-02 mrem/yr	2.11E-02 mrem/yr	0.141%
Radioiodines and Particulates Released to the Atmosphere				
Dose to any organ from all pathways	15 mrem/yr	1.88E-02 mrem/yr	2.05E-02 mrem/yr	0.137%

Table 2.10.1-3
Current Licensing Basis Vital Area Access Dose Summary

Accident Mitigation Task	Whole Body Dose (rem)	
	Primary route	Alternate route
1. Local tripping of the reactor trip breakers and bypass breakers in the 43′ 6″ level of the Aux. Building in the MCC Rod Control Area	2.91	2.61
2. PASS Sample	NA	NA
3. Local realignment of spent fuel pool cooling, RBCCW and service water for spent fuel pool cooling in the Spent Fuel Building	0.35	0.66
4. Powering of the Plant Process Computer from the Turbine Building	1.35	NA
5. Powering of the safety injection accumulator valves in the 24′ level of the Aux. Building	4.62	4.46
6. Initiation of the hydrogen monitor in the Hydrogen Recombiner Building	3.25	4.02
7. Initiation of the hydrogen recombiner in the Hydrogen Recombiner Building (Not a required Action)	NA	NA
8. Initiation of the hydrogen purge from the 4', 24′ 6″ and 43′ 6″ levels of the aux. building (Not a required Action)	NA	NA
9. Local opening of the breakers for RWST/charging pump suction valves in the 24′ 6″ level of the Aux. Building	4.62	4.46
10. • Monitoring of porous concrete ground water removal system • Maintenance of porous concrete ground water removal system • Repower ESF Sump Pump	3.60 2.10 4.88	3.60 2.11 4.88
11. Opening of the breakers for non-safety grade sump pumps • combined Aux Bldg and ESF Bldg activities	1.49	1.49
12. Tripping of non-QA fans that may still be operating and venting of SLCRS damper leakage from the 43′ 6″ level of the Aux. Building	1.81	1.65

Table 2.10.1-3
Current Licensing Basis Vital Area Access Dose Summary

Accident Mitigation Task	Whole Body Dose (rem)	
	Primary route	Alternate route
13. Alignment of Service Water to Auxiliary Feedwater to provide long term decay heat removal • ESF Motor Driven Pump Compartment • ESF Terry Turbine Compartment	4.09 4.08	4.11 4.10
14. Closing of SLCRS Doors (Not a required Action)	NA	NA
15. Resetting of MCC Breakers for Diesel Generator Keep Warm Systems	0.52	NA

Table 2.10.1-4
SPU Vital Area Access Dose Summary

Accident Mitigation Task	Whole Body Dose (rem)	
	Primary route	Alternate route
1. Local tripping of the reactor trip breakers and bypass breakers in the 43′ 6″ level of the Aux. Building in the MCC Rod Control Area	3.55	3.19
2. PASS Sample (Not a required Action)	NA	NA
3. Local realignment of spent fuel pool cooling, RBCCW and service water for spent fuel pool cooling in the Spent Fuel Building	0.43	3.03
4. Powering of the Plant Process Computer from the Turbine Building	1.66	NA
5. Powering of the safety injection accumulator valves in the 24′ level of the Aux. Building	4.71	4.58
6. Initiation of the hydrogen monitor in the Hydrogen Recombiner Building	3.15	3.84
7. Initiation of the hydrogen recombiner in the Hydrogen Recombiner Building (Not a required Action)	NA	NA
8. Initiation of the hydrogen purge from the 4', 24′ 6″ and 43′ 6″ levels of the aux. building (Not a required Action)	NA	NA
9. Local opening of the breakers for RWST/charging pump suction valves in the 24′ 6″ level of the Aux. Building (Not a required Action)	NA	NA
10. Repower ESF Ground Water Sump Pump • Work in ESF Building • Work in ESF yard north of the RWST	2.04 4.75	2.13 4.82
11. Opening of the breakers for non-safety grade sump pumps • combined Aux Bldg and ESF Bldg activities (Work can be completed in the Service Building – a low dose area)	negligible	negligible
12. Tripping of non-QA fans that may still be operating and venting of SLCRS damper leakage from the 43′ 6″ level of the Aux. Building (Not a required Action)	NA	NA

Table 2.10.1-4
SPU Vital Area Access Dose Summary

Accident Mitigation Task	Whole Body Dose (rem)	
	Primary route	Alternate route
13. Alignment of Service Water to Auxiliary Feedwater to provide long term decay heat removal • ESF Motor Driven Pump Compartment • ESF Terry Turbine Compartment	4.54 4.53	4.56 4.56
14. Closing of SLCRS Doors (Not a required Action)	NA	NA
15. Resetting of MCC Breakers for Diesel Generator Keep Warm Systems	0.54	NA

2.11 Human Performance

2.11.1 Human Factors

2.11.1.1 Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The DNC human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system changes made to implement the proposed SPU. The DNC review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed SPU.

The acceptance criteria for human factors review are based on GDC-19, 10 CFR 50.120, 10 CFR 55, and the guidance in Generic Letter 82-33.

Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0 and guidance provided in Matrix 11 of RS-001.

MPS3 Current Licensing Basis

MPS3 design was reviewed against NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants," July 1981, Sections 13.2.1, Rev. 0; 13.2.2, Rev. 0; and 13.5.2.1, Rev. 0. The MPS3 design was not reviewed against SRP Section 18.0, because SRP Section 18.0 was not issued at the time.

The design bases of MPS3 was measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, as amended through October 27, 1978. The adequacy of the MPS3 design relative to the General Design Criteria (GDC) is discussed in FSAR Section 3.1.2.

Specifically, the adequacy of MPS3 safety-related structures, systems, and components with respect to nuclear design relative to conformance to:

- GDC-19, Control Room, is described in FSAR Section 3.1.2.19.

  The control room provided is equipped to operate MPS3 safely under normal and accident conditions.

  In the unlikely event the control room should be uninhabitable, an auxiliary shutdown panel located in the west switchgear room has equipment, controls, and instrumentation to accomplish, in conjunction with controls and indication located on the adjacent 4160V emergency switchgear, a prompt hot shutdown and a safety grade cold shutdown. The panel is physically located outside the control room.

As discussed in FSAR Section 18.1, a control room design review (CRDR) was performed utilizing the guidance contained in Supplement 1 to NUREG-0737, "Clarification of TMI Action Plan Requirements," and NUREG-0700, "Guidelines for Control Room Design Reviews." The objective of performing the CRDR was to ensure that the MPS3 control room provides an effective safe control center such that operators can satisfactorily perform the necessary functions required during normal operating, transient, and emergency conditions.

The scope of the CRDR included the controls, displays, and other components on the control boards, peripheral consoles, back panels, communication equipment, ancillary devices, and procedures that the control room operators would be expected to interface with. The remote shutdown panels were also included in the CRDR.

Following completion of the CRDR, a summary report was transmitted to the NRC on November 1, 1984. Addendum 1 to the summary report was submitted to the NRC on September 12, 1985, and Addendum 2 was submitted on November 14, 1985. The NRC Staff resolved all issues related to the CRDR in Supplement 4 to the MPS3 SER (NUREG-1031).

As described in FSAR Section 13.2, formal training programs have been established to train and qualify the personnel who operate and maintain the MPS3.

These programs are structured to fulfill the requirements of 10 CFR 55 and 10 CFR 50.120 using training criteria set forth in ACAD 02-001, National Academy for Nuclear Training, "The Objectives and Criteria for Accreditation of Training in the Nuclear Power Industry." The programs are based on a systems approach to training and are accredited by the National Academy for Nuclear Training. Initial accreditation of these programs was awarded on August 21, 1986, for operator training and on December 15, 1987, for maintenance and technical training. These programs are implemented for the following categories of nuclear power plant personnel: non-licensed operator, reactor operator, senior reactor operator, shift supervisor (/manager), shift technical advisor, instrument and control technician, electrical maintenance personnel, mechanical maintenance personnel, chemistry technician, radiological protection technician, and engineering support personnel. It also includes continuing (requalification) training for licensed personnel.

As discussed in FSAR Sections 13.5.2.1.4, and 13.5.2.1.5, Abnormal and Emergency Operating Procedures are prepared for abnormal and emergency operating conditions.

An abnormal operation is a condition that could degrade into an emergency or could violate Technical Specifications if proper action is not taken. These procedures identify the symptoms of the abnormal condition, automatic actions that may occur, and the appropriate immediate and subsequent operator actions.

Emergency Operating Procedures are prepared for conditions that may possibly lead to injury of plant personnel or the public if the release of radioactivity in excess of established limits occurs. These procedures include symptoms of the emergency conditions, automatic actions that may or should occur, and immediate and subsequent operator actions.

NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Power Station, Units 2 and 3, dated August 1, 2005, defines the scope of License Renewal. Human factors issues were not within the scope of License Renewal.

2.11.1.2 Technical Evaluation

Introduction

Human factors engineering and human performance initiatives are foundational characteristics that help ensure the plant operators can effectively and safely operate the facility as well as mitigate emergency conditions. When initiating a plant change, the design change process prompts completion of a human factors review for changes that may impact the control room layout (alarms, indication, appearance or performance). In addition, a MPS3 Operations' representative participated in SPU planning and modification development.

Description of Analysis and Evaluations

The following provides DNC's response to the standard set of considerations provided in RS-001.

1. Changes in Emergency and Abnormal Operating Procedures

Describe how the proposed SPU will change the plant emergency and abnormal operating procedures.

DNC Response:

The existing emergency and abnormal procedure set will continue to provide adequate guidance to cover the spectrum of anticipated events. The following procedure changes are intended to incorporate physical plant changes resulting from SPU. In addition to the more significant items listed below, minor changes (typically setpoints) have been identified for several emergency, abnormal and other operating procedures.

The following changes are required to be made to the emergency and abnormal procedures:

1. Auxiliary feedwater flow requirements will increase for certain events. This is reflected in appropriate procedures.

2. Actions added to ensure the control room emergency ventilation system is automatically placed in the filtered recirculation mode of operation within 30 minutes of a fuel handling accident.

3. A cold leg injection permissive is added that requires RCS pressure to be less than the low-pressure reactor trip setpoint (1900 psia) concurrent with an SI signal to automatically open the high-pressure injection valves. As a result, an additional check is added in E-0 to verify ECCS flow when RCS pressure is less than 1900 psig.

When determining if RCPs should be stopped throughout the EOPs, the operators are required to check at least one of the charging or SI pumps is "capable of delivering flow to the RCS." This check is in addition to ensuring that a charging or SI pump is running. Also, during the response to a loss of heat sink event, when verifying an RCS feed path, a new step for opening the cold leg injection valves is added.

Conclusion:

The minor changes to the emergency and abnormal procedures do not alter basic mitigation strategies and will be adequately implemented by the normal procedure change process and operator training program.

2. Changes to Operator Actions Sensitive to Power Uprate

Describe any new operator actions needed as a result of the proposed SPU. Describe changes to any current operator actions related to emergency or abnormal operating procedures that will occur as a result of the proposed SPU. Identify and describe operator actions that will involve additional response time or will have reduced time available. The response should address any operator workarounds that might affect these response times. Identify any operator actions that are being automated or being changed from automatic to manual as a result of the power uprate. Provide justification for the acceptability of these changes.

DNC Response:

The following changes to operator actions are required:

1. The time allowed for initiation of hot and cold leg recirculation to minimize boron precipitation for large-break LOCAs is reduced from nine (9) to six (6) hours.

2. Automatic rod withdrawal is disabled. As a result, the operator is required to manually withdraw rods to maintain T_{avg} on program when performing abnormal procedures requiring plant power changes.

Conclusion:

The changes do not significantly impact normal operator actions or off-normal event mitigation strategies. The changes will be appropriately proceduralized and the operators will receive formal classroom and simulator training for their implementation.

3. Changes to Control Room Controls. Displays and Alarms

Describe any changes the proposed SPU will have on the operator interfaces for control room controls, displays, and alarms. For example, what zone markings (e.g. normal, marginal and out-of-tolerance ranges) on meters will change? What setpoints will change? How will the operators know of the change? Describe any controls, displays, alarms that will be upgraded from analog to digital instruments as a result of the proposed SPU and how operators will be tested to determine they could use the instruments reliably.

DNC Response:

Changes to control room controls and displays will not be extensive and will generally include: 1) expanding scales for identified instrumentation, 2) changes to several control board and computer alarms, and 3) limited changes to plant control systems. There are no plans to change any analog displays or controls to digital.

A summary of the significant changes is provided below:

1. The following Control Room instrument loops are affected by SPU (calibration range, scaling or transmitter changes):

    - Turbine throttle and intermediate pressure scales

2. Alarm response (AR) procedures for the following function require revision as a result of setpoint changes and changes in plant response to transients.

   - Pressurizer relief tank high and low level alarm setpoints.

3. Process computer system setpoints will be changed for the following parameters:

   - Main feedwater and main steam system alarms
   - RCS delta-T alarm and protection
   - RCS T_{avg}
   - Pressurizer level
   - First stage pressure
   - Other various alarm changes

4. The following controls and control systems will be changed:

   - Turbine-driven feedwater pump control setpoint (Master speed control)
   - Turbine control valve setpoints
   - Steam dump valve control deadband and modulation setpoints
   - Elimination of control rod automatic withdrawal
   - OPT/OTT setpoints
   - T_{hot} filter addition
   - Pressurizer level program
   - RCS T_{avg} program
   - Control room emergency ventilation system – automatic placement in pressurized filtration mode of operation.
   - Cold Leg Injection Permissive on low RCS Pressure
   - P-8 permissive setpoint change

Conclusion:

The operators will be provided detailed training related to the SPU modifications and resulting control board and procedure changes. Operators are provided station modification review packages, and, when appropriate, classroom and simulator training. The initial startup of the uprated plant will be implemented as an Infrequently Conducted/Complicated Evolution (ICCE) and will be controlled by the Power Ascension Testing Plan.

4. Changes on the Safety Parameter Display System

Describe any changes to the safety parameter display system resulting from the proposed SPU. How will the operators know of the changes?

DNC Response:

In addition to the changes described above, the Critical Safety Function status trees will be reviewed and revised as necessary for related changes to setpoints.

Conclusion:

These changes will be addressed by the normal plant change processes, Operations will be involved in the modification process, procedure change reviews and operator training program modification training.

5. Changes to the Operator Training Program and the Control Room Simulator

Describe any changes to the operator training program and the plant referenced control room simulator resulting from the proposed SPU, and provide the implementation schedule for making the changes.

DNC Response

The existing licensed and non-licensed operator training programs employ the Systematic Approach to Training (SAT) process, which has provisions for ensuring adequate training is provided for significant plant modifications prior to implementation. Training will focus on Technical Specification changes, procedure changes and SPU modifications. Comprehensive training for the scope of changes associated with the SPU scope will begin during the 2008 continuing training cycles and will include classroom and simulator training and testing on the SPU changes. The operators will be able to demonstrate understanding of the integrated plant response using the simulator. Additional Just-in-Time (JIT) startup training will be provided to the operation crews conducting the ICCE startup. As necessary, this JIT training will also cover the startup-testing plan both in classroom and on the simulator.

Plant uprate modifications will be reviewed to determine impact on the simulator. Changes to the simulator modeling will be accomplished on a schedule established to meet the operator training program requirements. The simulator load for the current plant configuration will remain unchanged and available for operator training. Status of the simulator configuration will be controlled through the established simulator change process. Any control board hardware changes, associated changes to indications, and replacements of indications with revised scaling, will be scheduled to accommodate the training program requirements.

Additionally, MPS3 Operations will be involved in the SPU modification and procedure review process, providing operational input as well as gaining knowledge of the plant changes. The procedural changes including the emergency and abnormal operating procedures will be reviewed, verified and validated by Operations personnel. This provides another process for exposing operators to the SPU changes and associated bases. These activities will provide a solid foundation for operator understanding and interaction during the formal SPU training sessions.

Conclusion:

The SPU results in a number of plant modifications, which will generate changes to the Technical Specifications, plant procedures, training simulator and training lesson plans. The MPS3 SAT process has, in the past, been extremely effective in training plant personnel on significant plant modifications and procedure changes. Training for implementation of the SPU modifications will be accomplished in accordance with this proven process.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Human factors are not in the scope of license renewal.

Results

The results of the SPU Human Factors review show that changes to plant procedures, when prepared in accordance with the current procedure change control process, will not alter the basic mitigation strategies with which the operators are familiar. Changes associated with instrument control systems, scaling, and setpoints will not introduce a level of complexity that would lead to misunderstanding of the parameter. Operator training will provide effective reinforcement of procedure and plant physical changes as well as building proficiency with the required operator action changes.

2.11.1.3 Conclusion

DNC has reviewed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed SPU and concludes that (1) the effects of the proposed SPU on the available operator action times have been appropriately accounted for and (2) appropriate actions have been taken to ensure operator performance is not adversely affected by the proposed SPU. DNC further concludes that MPS3 will continue to meet its current licensing basis with respect to the requirements of GDC-19, 10 CFR 50.120, and 10 CFR 55 following implementation of the proposed SPU. Therefore, DNC finds the proposed SPU acceptable with respect to the human factors aspects of the required system changes.

2.12 Power Ascension and Testing Plan

2.12.1 Approach to SPU Power Level and Test Plan

2.12.1.1 Regulatory Evaluation

The purpose of the SPU test program is to demonstrate that SSCs will perform satisfactorily in service at the proposed SPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with the design criteria at SPU conditions. The DNC review included the following:

- Plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance,
- Transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and
- The test program's conformance with applicable regulations.

The acceptance criteria for the approach to SPU power level and test plan are based on:

- 10 CFR 50, Appendix B, Criterion XI insofar as it relates to establishment of a test program to demonstrate that SSCs will perform satisfactorily in service at the proposed SPU power level.

Specific review criteria are contained in the SRP, Section 14.2. Although it is not required for an SPU, the test plan was developed consistent with the guidance provided in Matrix 12 of RS-001.

MPS3 Current Licensing Basis

The MPS3 initial startup test program is described in FSAR Section 14.2.1. FSAR Section 14.2.7 identifies test program conformance with Regulatory Guides. The MPS3 initial startup test program was reviewed in accordance with NUREG-0800 Standard Review Plan for the Review of Safety Analysis Report for Nuclear Power Plants, July 1981, SRP Section 14.2, Rev. 2.

On July 22, 1986, a summary report of the MPS3 startup and power ascension testing was submitted to the NRC. This report includes the startup test program conduct and results, and spans the period from initial fuel loading through commercial operation and warranty run. NUREG-1031, Supplement 3 documents the NRC review of the test program results.

2.12.1.2 Technical Evaluation

2.12.1.2.1 Introduction

This testing plan will demonstrate that changes made to MPS3 hardware and instrumentation and control systems have been properly designed and implemented, and that MPS3 can be safely operated at the SPU power level. Implicit in the SPU power ascension test plan is the demonstration that the engineering calculations are correct and the completed analyses bound SPU operation. The MPS3 SPU test plan will confirm satisfactory performance for low power physics testing and full power operation at SPU power level, and demonstrate that all design criteria are satisfied.

2.12.1.2.2 Background

The MPS3 initial startup test program was accomplished in nine distinct and sequential major phases. The test program was performed to ensure the safe and efficient MPS3 operation up to 3411 MWt. Pre-operational tests were performed in both cold shutdown and hot standby conditions. Low power tests were completed following initial criticality. Power ascension to maximum licensed power was accomplished in increments of approximately 10 percent power. Testing and data collection were performed at the major power plateaus of 30, 50, 75, 90 and 100 percent power. The startup and power testing program results substantiated design predictions.

2.12.1.2.3 Proposed Power Ascension Test Plan

The SPU test plan will be developed considering three aspects:

- Power ascension testing, including low power physics testing
- Vibration monitoring
- Post-modification testing for plant changes

2.12.1.2.3.1 Power Ascension Testing

Following the completion of post refueling low power physics testing, power ascension testing will be conducted to ensure MPS3 can be safely operated at the SPU power level. SPU required modifications and modifications to improve margins, plant performance and efficiency are listed in Section 1.0, Introduction to the Millstone Power Station, Unit 3 Stretch Power Uprate Licensing Report.

2.12.1.2.3.2 Vibration Monitoring

A vibration monitoring activity will be included in the power ascension procedure to monitor plant response at various power levels. Vibration monitoring will be performed on systems and components reasonably affected by the SPU and the attendant increases in steam and feed flow. Vibration effects were evaluated with consideration of flow increases.

There are no MPS3 RCS (primary side) mass or volumetric flow rate changes. Flow induced vibration at SPU conditions was evaluated for the reactor vessel internals and steam generator tubes. The proposed SPU does not adversely impact the reactor vessel internals structural integrity. Operation at the uprated conditions will not result in rapid rates of steam generator tube wear or high levels of tube vibration to the general tube population. Therefore, vibration issues on the plant primary side are not expected.

SPU implementation will result in higher flow rates for piping systems within the main power cycle. Secondary system piping and supports evaluated included the following:

- Main Steam
- Extraction Steam

- Feedwater
- Condensate
- Feedwater Heater Vents and Drains
- Moisture Separator Vents and Drains

The evaluations concluded that piping systems remain acceptable and will continue to satisfy design basis requirements. Piping vibration reviews, including system walk-downs, will be performed during power ascension to the SPU level, to ensure piping system and component vibrations remain acceptable.

Specific secondary piping or components in the vibration monitoring scope include:

Systems

- Main and extraction steam lines
- Feedwater and condensate lines
- Moisture separator reheater and heater drain lines

Turbine Generator

Components

- Feedwater, heater drain, and condensate pumps and motors

Note: Main feedwater pump speed will increase in proportion to the SPU power. Increased feedwater flow results from the increased speed.

2.12.1.2.3.3 Post-modification Testing

Post modification testing will validate the engineering analysis and implementation of changes. Post-modification tests for each modification will be carried out in accordance with MPS3 design change control procedures.

2.12.1.2.3.4 SPU Restart Procedure

A dedicated SPU restart procedure will be written to augment the normal start-up procedure. The SPU restart procedure will:

- Control the sequence and coordination of existing plant start-up procedures, with new procedures written to validate the associated SPU changes
- Ensure that the engineering analysis and subsequent implementation of modifications, setpoint changes and calibrations are correct
- Allow safe ascension to the SPU power level.

This procedure will reference dedicated SPU test procedures, including the gathering of plant thermal and electrical performance data. The SPU test procedures and results will be reviewed and approved by engineering, management, and the site safety review committee. Per Technical

Specification 6.9.1.1, an SPU start-up report will be created and sent to the NRC within 90 days of completing the start-up test program.

Table 12.12-1 describes the SPU testing, related modifications, and the areas of increased monitoring. The SPU test program consists of a combination of normal surveillances and start-up testing, and special testing.

Testing as part of normal surveillances and start-up testing will include:

- Core loading prerequisites
- Initial core loading
- Rod drop time measurements
- Rod position indication
- RCS flow measurement
- Operational alignment of nuclear instrumentation
- Operational alignment of process temperature instrumentation
- Initial criticality
- Boron endpoint measurement
- Isothermal temperature coefficient measurement
- Control rod worth measurement
- Thermal power measurement and setpoint data collection, including calorimetric normalization
- Core performance evaluation
- Axial flux difference instrumentation calibration
- Loss of offsite power testing (integrated safeguards testing)
- Post-modification testing as required by the design change process, including setpoint verification

Special SPU testing will include:

- T_{ave} optimization
- Start-up adjustments to the reactor control system
- Calibration of steam and feedwater flow instrumentation
- NSSS acceptance testing
- Turbine generator start-up testing
- Flow induced vibration monitoring
- Secondary system monitoring

The power ascension above 3411 MWt will take place over several days. Data and monitoring will take place while the plant is stable at discrete increments.

2.12.1.3 Conclusion

DNC has reviewed the approach to SPU Power Level and test program, including plans for the initial approach to the proposed maximum licensed thermal power level, transient testing necessary to demonstrate the plant equipment will perform satisfactory at the proposed increased maximum licensed thermal power level, and the test program's conformance with applicable regulations. DNC concludes that the approach to SPU Power Level and test program provides adequate assurance that the plant will operate in accordance with design criteria, and that SSCs affected by the proposed SPU will perform satisfactorily. DNC concludes that the SPU testing program meets the requirements of 10 CFR 50, Appendix B, Criterion XI. Therefore, DNC finds the proposed approach to SPU Power Level and test program acceptable.

Table 2.12-1
SPU Power Ascension Test Plan Summary

SYSTEM/ COMPONENT	MODIFICATION DESCRIPTION	TESTS
Main Feedwater Pump	Turbine replacement	1. Post modification testing 2. Monitor pump speed 3. Monitor discharge pressure and flow 4. Monitor pump vibration 5. Confirm increased main feed pump turbine steam flow at anticipated values
Turbine building HVAC	Modified ductwork to provide additional ventilation cooling in the condensate pump area.	1. Post modification testing after ductwork modifications are complete
Control Building Ventilation	Control Building auto initiation of pressurized filtration following Control Building isolation signal	Series of post-modification tests to verify changes: 1. Equipment calibration 2. Input of various control signals 3. Manipulation of component controls 4. Cycling of components 5. System operation

Table 2.12-1
SPU Power Ascension Test Plan Summary

SYSTEM/ COMPONENT	MODIFICATION DESCRIPTION	TESTS
Turbine Generator	1. New operating point for generator exitation 2. Control valve position demand vs. lift settings for the valve position cards 3. Changes to power load imbalance circuits 4. Throttle pressure and excess throttle pressure circuit recalibrations 5. Sensor rescaling for steam pressure changes 6. Instrument scaling 7. Main control board & panel meter replacements	Series of post-modification tests to verify changes: 1. Equipment calibration 2. Input of various control signals 3. Manipulation of component controls 4. Cycling of components 5. System operation 6. Confirm proper indication for uprated conditions.
Instrumentation & Control Systems	Setpoint changes 1. BOP system 2. Feedwater pump 3. Pressurizer level control 4. Electronic filter on T_{hot} signal 5. PRT level alarm 6. Condenser steam dump trip valve control 7. P-8 setpoint change	1. Verify setpoint changes correctly implemented via the MPS3 design control program. 2. Verify proper system operation at uprated conditions. 3. Post modification test
Pipe Support Modifications: QSS/RSS, Condensate, Feedwater, Component Cooling Water System and Extraction System	Pipe support modifications	1. NDE 2. QC inspections 3. Applicable Systems Vibration monitoring 4. System walk-downs (outside Containment)

Table 2.12-1
SPU Power Ascension Test Plan Summary

SYSTEM/ COMPONENT	MODIFICATION DESCRIPTION	TESTS
ECCS	Permissive for opening cold leg injection valves	Series of post-modification tests to verify changes: 1. Equipment calibration 2. Input of various control signals 3. Manipulation of component controls 4. Cycling of components
Instrument Loop Rescaling	1. Isophase bus duct cooler flow 2. MSR steam flow 3. First stage turbine pressure	1. Post modification testing 2. Confirm proper indication for uprated conditions.
Rod Control System	Deletion of automatic rod withdrawal capability	Series of post-modification tests to verify changes: 1. Input of various control signals 2. Manipulation of component controls to show that control rods do not withdraw under control inputs that previously would have resulted in outward rod motion
POWER ASCENSION TESTING SUMMARY		
Piping Systems Outside Containment	NA	Vibration monitoring program
Ventilation Systems	NA	Ventilation system operability test (TRM)
Chemical and Volume Control System	NA	Maintain primary and secondary chemistry within the requirements of the Chemistry Control Program
Plant Process Computer	NA	Verify calorimetric calculation is correct
Reactor Core	NA	Utilize plant procedures for post-refueling power physics testing and MPS3 uprate power ascension testing to verify applicable core design parameters

Table 2.12-1
SPU Power Ascension Test Plan Summary

SYSTEM/ COMPONENT	MODIFICATION DESCRIPTION	TESTS
NSSS	NA	1. Utilize MPS3 uprate power ascension testing procedure to trend parameters, evaluate data, and rescale instrumentation (ΔT, Nuclear Instrumentation, turbine impulse pressure) 2. Ensure systems that determine reactor thermal power are properly calibrated
Engineered Safety Features (ESF) Equipment	NA	Utilize Technical Specification surveillance program to verify ESF Systems operability
Plant Radiation Levels	NA	Utilize MPS3 Radiation Protection Manual to verify acceptable plant radiation levels.

2.13 Risk Evaluation

This section describes the risk analysis associated with the stretch power uprate (SPU). This SPU evaluation is not submitted as a risk-informed license application. However, it is recognized that there can be potential risk changes associated with the increased core power. This risk evaluation is provided for information purposes and insights. The evaluation addresses the power uprate impacts on the internal events, external events and shutdown operations. Therefore, this section is organized into the following sections:

2.13.1 Regulatory Evaluation

2.13.2 Technical Evaluation

2.13.2.1 MPS3 PRA Overview

2.13.2.2 Internal Events Risk

2.13.2.3 External Events Risk

2.13.2.4 Shutdown Operation Risk

2.13.2.5 PRA Quality

2.13.2.6 Technical Evaluation Conclusion

2.13.3 Conclusion

Attachment A – PRA Model Reviews

2.13.1 Regulatory Evaluation

DNC conducted a risk evaluation to: 1) demonstrate that the risks associated with the proposed SPU are acceptable and 2) determine if “special circumstances” are created by the proposed SPU. As described in Appendix D of the Standard Review Plan Section 19, special circumstances are present if any issue would potentially rebut the presumption of adequate protection provided to meet the deterministic requirements and regulations. The DNC review covered the impact of the proposed SPU on core damage frequency (CDF) and large early release frequency (LERF) for the plant due to changes in the risks associated with internal events, external events, and shutdown operations. In addition, the DNC review covered the quality of the risk analyses used to support the application for the proposed SPU. This quality review included a peer review of the Millstone 3 (MPS3) probabilistic risk assessment (PRA) model by the Westinghouse Owners Group and a self-assessment against the American Society of Mechanical Engineering (ASME) PRA standard (Reference 2) performed by an independent PRA contractor. The NRC’s risk acceptability guidelines are contained in RG 1.174. Specific review guidance is contained in Matrix 13 of RS-001 and its attachments. The SPU is not a risk-informed application, therefore the risk evaluation is provided for information only.

MPS3 Current Licensing Basis

The MPS3 Level 1 and Level 2 PRA model was initially developed in response to NRC Generic Letter 88-20, which the Individual Plant Examination (IPE) was developed (Reference 4). Since the original IPE submittal, the PRA model has undergone several model revisions to incorporate improvements and maintain consistency with the as-built, as-operated plant. The current PRA model includes extensive revisions that addressed the following:

- A & B level facts & observations (F&Os) from the Westinghouse Owners Group industry peer review
- ASME PRA standard supporting requirements (SRs) not met based on a RG 1.200 self assessment

2.13.2 Technical Evaluation

2.13.2.1 PRA Model Overview

Overall, the MPS3 PRA model has been reviewed and upgraded with the goal of increasing the quality and fidelity in areas related to the SPU.

The severe accident risk evaluation uses the latest MPS3 PRA, which is modification D of the 2005 PRA model (2005 is when the data in the model was updated). Various aspects of the model development are described in the following sections of this risk evaluation. The PRA model is a Level 1 and 2 model that includes internal events and internal floods. It does not include logic for quantifying external events such as fire, seismic, or shutdown risks. Therefore, the SPU impact in these areas will be assessed separately using the insights from the IPE external events including fire and seismic initiating events. Note that the external events analysis for MPS3 was summarized in the IPE submittal. The risk management program in place for shutdown operations will be evaluated with respect to how the SPU impacts the risk while the unit is in shutdown.The current PRA internal events model average annual CDF and LERF (pre-SPU) are as follows:

CDF due to internal events & flooding = 6.4E-06/yr

LERF due to internal events & flooding = 5.3E-07/yr

The core damage risk due to fires as evaluated in the IPE is as follows:

CDF due to fire events = 4.8E-06/yr

The core damage risk due to seismic events as evaluated in the IPE using a seismic PRA model, is as follows:

CDF due to seismic events = 9.1E-06/yr

The impact of the SPU on the above risk metrics is discussed in the following subsections.

2.13.2.2 Internal Events Risk

The MPS3 PRA uses the standard small event tree/large linked fault tree Level 1 methodology. Event trees are developed for each unique class of identified internal initiating events and top logic is developed to link these functional failures to system-level failure criteria using the Computer Aided Fault Tree Analysis (CAFTA) code (Reference 5). Fault trees, comprised of component and human failure events, are developed for each of the systems identified in the top logic.

Bayesian updating generic industry data with MPS3 plant-specific data quantifies fault tree hardware-related failures. This data is updated on a periodic basis with data from the Maintenance Rule program as well as other plant sources. Section 2.13.2.5.1.4 contains additional information on the data used in the PRA.

Human failure events are quantified using human reliability analysis (HRA) to obtain the probability of failure of operator actions modeled. Both pre-initiator and post-initiator human errors are included in the model. The Accident Sequence Evaluation Program (ASEP) is used to quantify pre-initiator events. For post-initiator events, a combination of HRA methods is used. The Cause-Based Decision Tree (CBDT) and Human Cognitive Reliability (HCR) methods are used for cognitive error probabilities. For execution error probabilities, the Technique for Human Error Rate Prediction (THERP) is used. Section 2.13.2.5.1.3 contains additional information about the human failure events in the PRA.

Solution of the event trees yields "cutsets," or those combinations of events that lead to core damage (and large early release). Sensitivity and importance analyses of the final results are also performed to help identify risk significance.

To fully assess the impact of the SPU on the internal events model, the following areas will be evaluated and discussed further in the sections that follow:

- Impact on Model Attributes
- Impact of Plant Modifications
- Level 2/LERF Analysis
- Total Estimated CDF and LERF Impacts

The individual impacts will be assessed in each section and then summed in the section on total impact.

2.13.2.2.1 SPU Impact on Model Attributes

Power uprates can impact various plant functions and operation that can change plant risk. Based on other plant submittals of power uprate license changes, the primary impacts of power uprates on PRA model attributes are:

- Initiators
- System/Function Success Criteria
- Operator Actions
- Component and System Reliability

This section will review the impact on these model attributes. The overall impact on CDF and LERF is discussed at the end of the internal events section.

2.13.2.2.1.1 Impact on Initiators

The MPS3 PRA addresses loss of coolant accidents (LOCAs), steam line breaks, steam generator tube ruptures (SGTRs), loss of offsite power (LOOP), internal flooding and transient events. The underlying contributors to these initiating events are reviewed to determine the potential effects of the SPU on the initiating event frequencies.

Loss of Coolant Accidents (LOCAs)

These frequencies (for all break sizes) are determined by the potential for passive pipe failures and are not related to reactor power level. The SPU does not involve changes to the reactor coolant system boundaries or interfacing system piping. As there are no substantive changes in the way the system is operated, the LOCA frequencies are not affected by the SPU.

A LOCA can also occur as a result of a reactor coolant system (RCS) pressure excursion that results in a stuck open power operated relief valve (PORV) or pressurizer safety relief valve (SRV). Given the power increase of the proposed SPU, it may be postulated that the probability of a stuck open PORV would increase due to any reductions in margins that could increase challenges to the PORV/SRV. The impact on CDF due to a stuck open PORV is very small given the Fussell-Vesely (FV) importance value of the PORV/SRV challenge basic event being 6.4E-03. Thus, a 10 percent increase in PORV challenges would only increase CDF by approximately 0.064 percent.

Steam Generator Tube Rupture (SGTR)

The MPS3 steam generators (SGs) are Westinghouse Optimized Model F SGs. Engineering analysis of the impact of the SPU on the various design and operation characteristics of the SGs indicates there are no adverse effects on the thermal hydraulics, structural integrity and flow induced tube vibration. Therefore, the SGTR initiating event frequency is not impacted by the SPU.

Loss of Offsite Power (LOOP)

Using plant-specific data and generic industry data through a Bayesian updating process derives the MPS3 LOOP initiating event frequency. The mean LOOP frequencies are as follows:

Plant Centered LOOP	8.28E-03/yr
Grid Related LOOP	2.62E-02/yr
Weather Related LOOP	3.65E-03/yr

The SPU is not large enough to impact grid reliability when the unit trips. Therefore, the SPU will not impact the grid or weather related LOOP frequencies. Plant adjustments (e.g., transformer tap positions) will be implemented to ensure the switchyard power equipment continues to operate within its design limits. Therefore, the plant centered LOOP frequency is not anticipated to be adversely affected by the SPU.

The FV importance value in the current PRA model of the plant centered LOOP basic event is 8.3E-02. Therefore, increasing the frequency by 10 percent to account for any unforeseen switchyard reliability issues would result in a CDF increase of approximately 0.83 percent, or 5.3E-08/yr.

Transients

The transients initiating event frequency is derived using plant-specific data and generic industry data through the Bayesian updating process. As part of the SPU effort, plant systems have been reviewed for continued operability at the SPU conditions. In some cases, system changes will be made so that the systems will adequately perform their functions at the SPU conditions. An example of these changes is resetting control and protection system instrument setpoints so that adequate operating margins are maintained.

Although it is anticipated that these changes will be implemented to maintain the transient initiating event frequency at its current level, industry experience indicates an increase in transients caused by power uprates. INPO has summarized events caused by problems stemming from power uprates in main steam systems, feedwater heaters, turbine control systems, feed flow and temperature measurement and main generator cooling. To account for any unforeseen issues relating to systems that could result in a transient, the CDF impact of a 10 percent increase in the general transient initiating event frequency (9.6E-01/yr) would result in an increase of approximately 1.6 percent, or 1.0E-7/yr, in CDF based on the Fussell-Vesely importance value of 1.6E-01.

Anticipated Transient Without Scram (ATWS)

Failure of the reactor to trip automatically following a transient is considered in the PRA ATWS model. The impact of the SPU on the nuclear steam supply system (NSSS) control systems and the control rod drive mechanisms were evaluated. The evaluations show that the initiating event frequency of ATWS events is not affected by the SPU conditions.

Support System Initiators

Support system fault initiating event frequencies are quantified using fault trees that model plant components. The initiating event frequencies quantified in this manner include those for loss of direct current (DC) power sources; loss of service water and loss of reactor coolant pump (RCP) seal cooling. There are no changes related to the SPU that would affect system success criteria, and therefore the initiating event frequency, as modeled in the PRA. It is concluded that the components and their reliability are not affected by the SPU conditions; therefore, the calculated initiating event frequencies in the current PRA remain applicable for the SPU.

2.13.2.2.1.2 Impact on System/Function Success Criteria

Success criteria are defined for the accident sequences modeled in the PRA to establish whether or not core damage occurs. The success criteria specify the systems and equipment required to function to address critical safety functions. These critical safety functions include reactivity control, RCS pressure control/pressure boundary integrity, RCS and core heat removal, RCS inventory control, and long-term RCS inventory control and heat removal. The success criteria used in the PRA are based on the following:

- Design basis calculations regarding number of trains required to satisfy a safety function
- Thermal hydraulic analysis performed to determine specific success criteria for PRA accident sequences (e.g. bleed and feed cooling of the RCS).

The design basis success criteria in the PRA have not changed with the SPU, as confirmed by analyses.

The PRA uses a limited set of thermal hydraulic analyses for establishing more specific success criteria. Table 2.13.2.2.1.2-1 contains success criteria for bleed and feed, offsite power recoveries and steam generator dryout.

The success criteria and operator action times listed in Table 2.13.2.2.1.2-1 were established in previous PRA model versions using the Modular Accident Analysis Program (MAAP) thermal hydraulics code (Reference 17). As part of the re-analysis for the SPU, the cases were analyzed using RELAP5. The success criteria were verified to remain applicable using the RELAP5 thermal hydraulic code for both the current core power level and the SPU power level. The results show that the success criteria remain valid for SPU conditions.

2.13.2.2.1.3 Impact on Operator Actions

The MPS3 PRA uses the Human Cognitive Reliability/Operator Reliability Experiment (HCR/ORE), Cause-Based Decision Tree (CBDT) and Technique for Human Error Rate Prediction (THERP) methods for calculating the human error probability (HEP) of post-initiator operator actions. The CBDT method considers how performance shaping factors influence cognition as part of using the cause-based decision trees. The HCR/ORE method for estimating cognition error probabilities considers the time available and time required completing the response. The method that results in the higher probability is selected for the cognitive error portion of the HEP. THERP is used to quantify the execution error, which considers the influence of performance shaping factors on operator stress and adjusts error probabilities based on the stress level.

The SPU has the general effect of reducing the time available for the operators to complete some actions, because of the higher decay heat level after the SPU implementation. The reduced time available can increase the probability of operator failure. Thermal hydraulic analyses had confirmed the current time windows used in the HCR/ORE calculation of the cognitive errors for MPS3. The operator actions credited in the PRA model are listed in Table 2.13.2.2.1.3-1. The table shows the time available to perform the actions along with the mean error probability and the Fussell-Vesely importance. It should be noted that the engineering times for the HEPs were established in previous model revisions using the MAAP thermal hydraulic code. These time windows were verified to remain valid using the RELAP5 code for the current and the SPU core power. Even though the RELAP5 analyses shows the time available for the HEPs could be extended (and thus reduce the HEP), the HEPs were not changed in order to allow some margin to account for uncertainties as well as to accommodate future plant changes.

The Fussell-Vesely (FV) importance of the HEPs shows that changes in the probabilities for nearly all of the HEPs will have very small impact on the CDF. The HEP for establishing bleed & feed (model basic event OAPBAF) is the only one that has a relatively high importance, which is expected due to the significance of the sequences involving bleed & feed. The FV importance of this operator action is 1.35E-01, which can be used to estimate the CDF impact of changes to the failure probability of this action. The CDF impact of a 10 percent change in this action would be approximately 1.3 percent of the CDF, or 8.1E-08/yr. Changes in the remaining operator action probabilities will have a negligible impact as indicated by the low FV importance values. The assessment of the impact on CDF and LERF in Section 2.13.2.2.4 includes a sensitivity in which the OAPBAF probability is changed to estimate the SPU impact on CDF and LERF.

2.13.2.2.1.4 Impact on Component and System Reliability

A review of the changes associated with the SPU was performed to determine their effect on systems and associated equipment that are important to plant risk. The unit will rely on existing component monitoring programs, such as the Maintenance Rule and the preventive maintenance program to identify any additional degradation as a result of the SPU. While the SPU may result in some components being refurbished or replaced more frequently, which may result in increased unavailability if performed while the plant is on-line, the functionality and reliability of components will be maintained to the current standard. These existing monitoring programs are also expected to identify any future deviations in component failure rates. The PRA maintenance and update process in place at Millstone provides the means for identifying any future impact on component failure rates and unavailability and addressing them in the PRA model.

2.13.2.2.2 Impact of Plant Modifications

The modifications to be implemented as part of the SPU were reviewed to identify impacts on the PRA. Many of the changes involve systems and components that are not explicitly modeled in the PRA. The main FW pumps are being modified to accommodate the higher FW flows for the SPU. Also, valve trim in the control valves is being changed. Setpoints and scaling changes are being made for various instruments. The changes do not have a direct impact on credit for components modeled in the PRA. But they could have an indirect impact on initiators as incorrect implementation may cause transients. This is noted in the sections assessing the impact of the SPU on initiators.

It is anticipated that there will be Emergency Operating Procedure changes to reflect the plant modifications and changes to setpoints and scaling factors. This can have an impact on the Human Error Probabilities. However, as discussed in Section 2.13.2.2.1.3, margin has been allocated to accommodate future plant changes.

One plant modification will reduce plant risk by reducing the impact of an inadvertent safety injection. The modification adds a low RCS pressure permissive to the opening of the cold leg injection valves when they receive a safety injection open signal. During an inadvertent safety injection, these valves will not open unless the RCS pressure drops due to a breach in the RCS. The additional logic does introduce another means of the valve failing to open. However, the unreliability of this additional logic is not significant with respect to the more dominant valve failures.

In conclusion, the modifications do not introduce new initiators, accident sequences, system or component failures or dependencies, or operator actions.

2.13.2.2.3 Level 2/LERF Analysis

The MPS3 PRA Level 2 analysis is a detailed, plant-specific containment performance evaluation. The Level 2 models utilize the data and conclusions of NUREG/CR-4550,

NUREG/CR-4896, NUREG/CR-6109, NUREG-1570, NUREG/CR-6075, NUREG/CR-6338, and NUREG-1524 (References 6 through 12) as they apply to MPS3, which has a large, dry containment. The Level 2 analysis includes a detailed containment event tree, with appropriate endstates tallied into a large, early release frequency (LERF) value. The Level 2 calculations are performed using the CDF accident sequences binned into plant damage states (PDSs). Sequence CDF results include the status of equipment considered important for continued containment integrity such as auxiliary feedwater, quench and recirculation sprays and containment heat removal. Containment isolation was also evaluated for LERF consideration.

The dominant contributors to LERF are steam generator tube rupture (SGTR) initiating events that lead to large, early bypasses, unscrubbed interfacing system loss-of-coolant accidents (ISLOCAs), and high RCS pressure core damage sequences with a dry secondary side that result in an induced SGTR.

Phenomena explicitly considered for LERF include:

- Steam explosions
- Induced SG tube ruptures
- Hydrogen burns
- Containment overpressurization due to steam
- Containment failure due to overtemperature
- Containment isolation failures

The plant changes due to the SPU were determined to have an insignificant or no adverse impact on the total failure contribution from these contributors. Current subatmospheric containment modeling in the PRAs assumes no pre-existing containment isolation failures. This assumption remains valid for the SPU as the containment vacuum pumps are expected to maintain the slightly subatmospheric condition unless there is a pre-existing containment isolation failure.

2.13.2.2.4 Estimated CDF and LERF Impacts

The internal events severe accident risk assessment of the above changes was evaluated by quantifying the MPS3 PRA for two cases:

- Baseline case – pre-SPU CDF and LERF
- SPU case – post-SPU CDF and LERF

The changes discussed in the preceding sections are summarized in Tables 2.13.2.2.4-1 and 2.13.2.2.4-2.

Table 2.13.2.2.4-3 shows the change in CDF and LERF to be less than the 1E-06/yr (for CDF) and 1E-07/yr (for LERF) thresholds in RG1.174 in which the change may be characterized as very small.

Table 2.13.2.2.4-4 shows the CDF for the different initiators. The SBO, ATWS, Steam Line Break Outside Containment and General Transient initiators show the largest changes primarily due primarily to the changes in the grid-related LOOP and general transient initiator frequencies, and in the offsite power recovery failure probabilities.

Table 2.13.2.2.4-5 shows the CDF importance for the major components modeled (front line systems and major support systems) and operator actions. The table shows the FV and RAW for pre and post SPU conditions. There is relatively little change in the importance of the components and operator actions. The importance of the EDGs and the offsite power recovery basic events increased slightly, which is expected since the plant centered LOOP initiating event frequency was increased as well as the offsite power recovery basic event probabilities. The importance of some basic events actually decreased slightly between the pre and post SPU conditions. This is due to the nature of the importance factors, which is relative to the CDF of the model solution.

In conclusion, the increase in CDF due to the SPU is estimated to be 4.0E-07/yr. The increase in LERF is estimated to be 2.0E-08/yr. Both of these are characterized as very small changes per RG 1.174.

2.13.2.3 External Events

The MPS3 PRA model is a Level 1 and 2 model that includes internal events and internal floods. For external events such as fire, seismic, extreme winds and other external events, the risk assessments from the Individual Plant Examination (IPE) (Reference 4) are used for insights on the impact of the SPU.

2.13.2.3.1 Fire Risk

The MPS3 PRA does not include a fire model. Therefore, the results of the external events fire risk assessment performed for the IPE were reviewed to qualitatively assess the impact of the SPU on fire risk. The IPE fire risk analysis quantified a CDF impact by combining the frequency of fires and the probability of detection/suppression failure with the remaining safety function unavailabilities. A systematic approach was used to identify critical fire areas where fires could fail safety functions and pose an increased risk of core damage if other safety functions are unavailable. The CDF due to fires is 4.8E-06/yr, with the dominant risk being fires in the cable spreading room, switchgear rooms, control room, and auxiliary building.

A review of the plant modifications resulting from the SPU indicates the modifications are not expected to change the frequency of fire initiators or create new ones as there are no significant changes in combustible loading. The SPU has a negligible impact on the mitigation of fires and resulting CDF due to loss of safety functions. The impact of the SPU on operator actions to suppress fires is negligible due to the redundancy with automatic suppression systems. The impact on other actions associated with transferring control to the auxiliary shutdown panel (ASP) and operating equipment at the breakers is not expected to be significant. The higher decay heat associated with the SPU is not expected to have a significant impact on the margin for operator actions or the mitigation strategy.

In conclusion, the impact of the SPU on fire risk is not considered to be significant. Since MPS3 is a relatively new plant that has many fire protection and other plant features that reduce the likelihood and consequences of fires, the CDF due to fires is relatively low.

2.13.2.3.2 Seismic Risk

The MPS3 PRA has not updated the seismic model since the IPE. Therefore, the results of the external events seismic risk assessment performed for the IPE were reviewed to qualitatively assess the impact of the SPU on seismic event risk. The IPE seismic risk analysis quantified a CDF impact by combining the seismic hazard frequencies with the fragilities of critical structures and components and the safety function unavailabilities to obtain a CDF. The CDF due to seismic events is 9.1E-06/yr, with the dominant risk being seismic events that result in a loss of offsite power and failure of the EDG enclosures, or collapse of the Control Building.

The plant changes implemented for the SPU are not expected to result in changes to structure or component response to a seismic initiator nor do they result in new seismic core damage or LERF scenarios. The plant modifications have a negligible impact on the structural response of the plant. Equipment installed or modified for the SPU will meet seismic design criteria. Only two operator actions are included in the seismic risk analysis:

- Operator fails to emergency borate during a seismic event resulting in an ATWS
- Operator fails to establish bleed and feed to mitigate a seismically induced small LOCA

The SPU will shorten the time available to perform these actions. However, it is not expected the increase in failure probabilities of these actions will have a significant impact on CDF.

In conclusion, the impact of the SPU on seismic risk is not considered to be significant.

2.13.2.3.3 High Winds, Floods and Other External Events

The risk of other external events such as high winds, aircraft accidents, hazardous materials and turbine missiles was assessed in the MPS3 IPE. The IPE assessments concluded that the risk of these accidents is negligible primarily due to the low frequency of occurrence that would cause damage to mitigating systems. For example, reinforced concrete houses that provide missile protection during high wind conditions protect all critical safety functions. The plant changes implemented for the SPU are not expected to have an impact on the CDF for these types of events.

2.13.2.4 Shutdown Risk

MPS3 uses the Equipment Out Of Service (EOOS) risk monitor for assessing configuration risk for at power and low power/shutdown conditions. The shutdown risk management is based on defense in depth logic in the EOOS program rather than on a PRA model that quantifies core damage and large early release frequencies. Therefore, the impact the SPU has on shutdown risk is based on a qualitative assessment of the shutdown risk management program.

The objectives of MPS3 Shutdown Risk (SDR) Management Program are to assess and manage risks to plant safety, and maintain Key Safety Functions by augmenting Technical Specification requirements during plant shutdown/outages. Industry experience has shown that meeting Technical Specification requirements alone during an outage will not effectively manage risks to plant safety associated with the outage. Therefore, additional requirements have been established to effectively manage outage risk.

The SDR Management Program provides a consistent means to minimize risks to plant safety during a Unit shutdown/outage by performing the following:

- Enhances management and worker awareness regarding risk
- Emphasizes steps to protect the following Key Safety Functions during Unit shutdown:
  - Decay Heat Removal
  - RCS Inventory Control
  - Electrical Power Availability
  - Reactivity Control
  - Containment
- Focuses attention on integrating outage planning and work control to minimize risks
- Ensures outage schedules receive a safety review *prior* to the start of outage activities
- Ensures adequate defense-in-depth for Key Safety Functions during outages
- Ensures outage schedule incorporates the results of the shutdown safety review
- Highlight actions to reduce the consequences of events occurring during shutdown
- Increase management and worker focus on outage planning and work control

The program also implements the recommendations of NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management" (Reference 13) and Millstone's self-assessments of unit practices with respect to minimizing shutdown risks.

Prior to an outage, an SDR team is established to perform a thorough shutdown safety assessment (SSA) review of the schedule to assess the impact of the activities on the key safety functions. The result is a pre-outage report of the overall risk profile that is used to for additional improvements in the schedule to further minimize the risk level and duration of the high-risk activities. Once the outage starts, the SDR team performs daily SSA reviews of the schedule for the next day to assess how schedule changes impact risk and whether risk management actions are required to reduce the risk. The EOOS risk monitor automates the assessment of risk by allowing the outage schedule to be imported into the program so that the results of the risk assessments for each change in configuration can be easily analyzed and displayed. A SSA checklist is also used to verify the risk levels of the outage activities and is maintained updated as the schedule changes.

For Higher Risk Evolutions (HRE) where the EOOS and SSA checklist indicate an orange risk level, a shutdown risk contingency plan is required. The plan generally requires the following:

- Identify equipment and tools required to support the plan
- Identify personnel designated to perform the plan
- Identify specific actions to provide/protect/maintain Key Safety Functions

- Assess the potential of equipment failures or mishaps (cranes, forklifts, etc.) during proposed work activity that could impact offsite power and other safety functions
- Identify additional monitoring or controls to ensure equipment remain functional

The primary impact of a power uprate on shutdown operations is the higher decay heat levels, which shortens the time to boil and operator response time to take mitigating actions. Impacts on equipment reliability or shutdown initiators are generally negligible. The following assesses the impact on each of the key safety functions.

RCS Decay Heat Removal

The Residual Heat Removal (RHR) system capacity remains adequate to maintain refueling temperatures and a uniform boron concentration in the Reactor Coolant System (RCS). The increase in decay heat due to the SPU will decrease the time for the operators to respond to a loss of shutdown cooling. Maintaining an adequate defense-in-depth for this safety function at all times minimizes the impact of this decreased response time. The SSA review of the outage activities determines the availability of the following for maintaining availability of this function: RHR trains; conditions that support natural circulation in the RCS (early in the outage); the refueling cavity flooded to 23 feet.

RCS Inventory Control

The increase in RCS temperature and the increase in decay heat will decrease the time for the operators to respond to a loss of RCS inventory control. Maintaining an adequate defense-in depth for this safety function minimizes the impact of this decreased response time. The SSA review evaluates plant configurations to determine the availability of the following systems for maintaining the inventory control function: charging pumps; high head safety injection pumps; RHR being capable of taking suction from the RWST.

AC Power Availability

The increase in RCS temperature and decay heat will decrease the time for the operators to respond to a loss of electrical power. Since the electrical power systems support the systems required for the other safety functions, maintaining an adequate defense-in-depth for this safety function minimizes the impact of this decreased response time. The SSA review evaluates plant configurations to determine the availability of the following systems for maintaining the AC power function: emergency diesel generators; Reserve Station Service Transformer (RSST); Normal Station Service Transformers (NSST); Station Blackout (SBO) diesel generator.

Reactivity Control

The safety analysis section (2.8.5.4.5) describes the analysis of the uncontrolled boron dilution event for SPU conditions. The increase in rated power was found to have a negligible impact on the results of the boron dilution event. The analysis showed that for dilution during refueling or dilution during cold shutdown with the RCS filled or partially drained, there is sufficient response time available.

Containment Integrity

The containment integrity safety function provides the capability to isolate the containment following a loss of another safety function. Thus, the response time for this safety function is decreased by the decreased response time for the other safety functions. Maintaining an adequate defense-in-depth for this safety function minimizes the impact of this decreased response time. Containment closure coordinators are responsible for monitoring containment penetration status and the closure status to ensure the containment can be closed within the time to boil. If the time to boil in the core is less than the time required to close the containment equipment hatch, the procedure requires that the hatch be closed for the duration of the refueling activity to maintain containment integrity for a postulated loss of decay heat removal function.

Low power shutdown modes

For low power shutdown modes, the SPU results in increased decay heat, which reduces the time for operator actions. However, the impact on risk is considered insignificant. The probability of core damage generally decreases at low power modes as some of the initiators are either no longer applicable or can be credited with reduced probability of occurrence. Also, all accident mitigating system remain available.

Conclusion

The increase in decay heat will result in a small decrease in the time available for operator actions during shutdown. However, maintaining an adequate defense-in-depth for the shutdown safety functions via the SDR management procedures minimizes the impact of this decreased response time. The SPU will have no unique or significant impacts on shutdown risk.

2.13.2.5 PRA Quality

The quality of modeling and documentation of the MPS3 internal events PRA model (which includes internal flooding) has been demonstrated by the discussions contained in this sections regarding the following aspects:

- Level of detail in PRA
- Maintenance of the PRA
- Comprehensive critical reviews

The MPS3 Level 1 and 2 internal events PRAs provide the necessary and sufficient scope and level of detail to allow the calculation of CDF and LERF changes due to the SPU.

In addition, the MPS3 internal events PRA has been used in support of various regulatory programs and relief requests that have received NRC Safety Evaluation Reports (SERs), further indication of the quality of the MPS3 internal events PRA and suitability for regulatory applications. This list includes:

- MPS3 Individual Plant Examination (IPE) Staff Evaluation Report (SER)
- Risk-Informed EDG 14 day AOT technical specification change
- Risk-Informed Inservice inspection (RI-ISI) SER

- Integrated Leak Rate Test (ILRT) frequency extension SER
- Life Extension (SAMA) License Amendment
- Cable Spreading Room Manual Fire Suppression
- Maintenance Rule
- Mitigating Systems Performance Index (MSPI)
- Significance Determination Process evaluations

2.13.2.5.1 Level of Detail

The MPS3 internal events PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. Each of these, as well as pertinent data and the Level 2 PRA, is discussed in this section.

2.13.2.5.1.1 Initiating Events

The MPS3 at-power PRA used in this application explicitly models a large number of initiating events:

- General transients
- Support system failures
- Loss of Coolant Accidents (LOCAs), including Interfacing System LOCA.
- Internal flooding events

The internal initiating events explicitly modeled in the MPS3 PRA are summarized in Table 2.13.2.5.1.1-1. The number of internal initiating events modeled in the MPS3 internal events PRA is similar to the majority of U.S. PWR PRAs currently in use.

2.13.2.5.1.2 System Models

The MPS3 internal events PRA explicitly models a large number of frontline and support systems that are credited in the accident sequence analyses. The MPS3 systems explicitly modeled in the MPS3 internal events PRA are summarized below. The number and level of detail of plant systems modeled in the MPS3 internal events PRA is comparable to the majority of U.S. PWR PRAs currently in use.

- Alternate AC or Station blackout diesel
- Auxiliary Feedwater
- Charging
- Reactor plant component cooling water
- Quench and Recirculation Spray
- Emergency & non-emergency Power

- Emergency Switchgear and Control Room Ventilation
- Instrument Air
- Main Feedwater
- Main Steam
- Reactor Protection/ESF Actuation
- Residual Heat Removal/Low Head Safety Injection
- Service Air
- Service Water
- Plus several other systems

  Note:This list is provided as general information as to the systems modeled in the MPS3 internal events PRA. This is not an exhaustive list of the systems modeled in the PRA with fault tree logic.

2.13.2.5.1.3 Operator Actions

The MPS3 internal events PRA explicitly models a large number of operator actions:

- Pre-initiator actions
- Post-initiator actions
- Recovery Actions

Over 90 individual operator actions (approximately 60 pre-initiator human error probabilities (HEPs) and approximately 30 post-initiator and recovery actions) are explicitly modeled. In addition, the MPS3 internal events PRA models approximately 40 dependent operator action combinations. Given the large number of actions modeled in the MPS3 internal events PRA, a summary table of the individual actions modeled is too large to include in this summary.

The human error probabilities for the actions are modeled with accepted industry human reliability analysis (HRA) techniques and include input based on discussion with cognizant personnel (emergency operating procedure (EOP) coordinator, operators and trainers). The following HRA methods are employed in the MPS3 internal events PRA:

- Pre-Initiator Human Failure Event (HFE) - Accident Sequence Evaluation Program (ASEP)
- Cognition Error of Post-initiator HFE - Cause-Based Decision Tree and Human Cognitive Reliability Model (HCR)
- Manipulation and Execution error of Post-initiator HFE - Technique for Human Error Rate Prediction (THERP).

The number of operator actions modeled in the MPS3 internal events PRA and the level of detail of the HRA, are comparable to those in many U.S. PWR PRAs currently in use.

2.13.2.5.1.4 Data

Initiating Event Frequencies

The frequency of each initiating event category is assessed using both MPS3 specific and generic data. The rare events such as LOCAs directly use the generic industry data. The sources of generic industry data are NUREG/CR-5750 (Reference 18) and NUREG/CR-INEEL-04-02326 (Reference 19). MPS3 plant experience is used in a Bayesian update statistical analysis with non-informative prior or in a fault tree analysis to produce the plant specific transient initiating event frequencies for use in the PRA.

Component Failure Rates (Generic)

The MPS3 internal events PRA has a defined priority for use of generic industry data for component failure rates. The primary preferred source of generic failure rates is EGG-SSRE-8875 Database (Reference 20). Secondary sources include NUREG/CR-4639 (Reference 21) and IEEE-STD-500 (Reference 22).

Component Failure Rates (Plant Specific)

The MPS3 internal events PRA plant-specific component data analysis is a Bayesian update statistical analysis of selected important equipment (typically in the scope of the Maintenance Rule monitoring) with an extensive set of plant specific data (obtained from the MPS3 Maintenance Program and other plant sources).

Maintenance and Testing Unavailability

The unavailability of components due to on-line maintenance and testing activities is estimated using either the MPS3 specific or generic industry data. Plant-specific unavailability data is primarily obtained from the MPS3 Maintenance Rule Program.

Common Cause Events

Dependent failures (i.e., common cause failures not due to support system failures) are also treated in the MPS3 internal events PRA model. Common cause failures (CCF) are evaluated for like components within a system. This includes similar components within different trains of the same system. Similar components in different systems, in general, are not modeled with common mode failures.

The MPS3 internal events PRA explicitly models a large number of common cause component failures. The number and level of detail of common cause component failures modeled in the MPS3 internal events PRA is similar to the majority of U.S. PWR PRAs currently in use. The common cause failure probabilities in the MPS3 internal events PRA are calculated using the -factor model. The factors used in calculating the MPS3 CCF probabilities are taken from the INEEL CCF database documented in NUREG/CR-5497 (Reference 23).

2.13.2.5.1.5 Level 2 PRA

The MPS3 Level 2 PRA is a large, early release frequency (LERF) model. The MPS3 Level 2/LERF PRA is a realistic, plant-specific model that incorporates the following features:

- LERF Containment Event Trees (CETs) designed for three types of core damage scenarios:
  - •• Containment intact at time of core damage
  - •• Containment failed at time of core damage
  - •• Containment bypassed at time of core damage
- LERF CETs address:
  - •• Containment isolation
  - •• In-vessel core damage progression and ex-vessel molten debris progression
  - •• Energetic phenomena
  - •• Emergency procedures (e.g., containment flooding)
- Level 1 PRA accident sequence logic and system logic linked directly into the
- LERF CETs
- Containment isolation failure fault tree based on plant-specific analysis
- Containment ultimate pressurization failure based on plant-specific analysis
- Accident progression timings and radionuclide release characteristics based on plant-specific thermal hydraulic analyses using the MAAP code (Reference 17)

2.13.2.5.2 Maintenance of PRA

The MPS3 internal events PRA model and documentation have been maintained as a living program, and are routinely updated approximately every 3 years to reflect the current plant configuration and to reflect system upgrades and component failure data.

The Level 1 and Level 2 MPS3 internal events PRA was originally developed in the 1980's from the Plant Safety Study (PSS). In 1990, after several changes, the PRA was submitted to the NRC for the IPE Submittal. The MPS3 internal events PRA has been updated many times since the original IPE. Table 2.13.2.5.2-1 provides a summary of the MPS3 PRA history.

An administratively controlled process is used to maintain configuration control of the MPS3 PRA model, data, and software. In addition to model control, administrative mechanisms are in place to assure that plant modifications, procedure changes, and system operation changes are appropriately screened, dispositioned, and scheduled for incorporation into the model in a timely manner. These processes help assure that the MPS3 internal events PRA reflects the as-built, as-operated plant within the limitations of the PRA methodology and resource availability. Updated PRA models undergo a design review by experienced PRA staff prior to release. The design review includes discussion of major changes to the model, review of the dominant risk contributors, and limitations on use of the model.

The EOOS risk monitor software is used by the Online Maintenance Organization as part of the requirements to comply with the 10 CFR 50.65(a)(4) Maintenance Rule. The model is extensively benchmarked with the full version of the event tree/fault tree CAFTA PRA model on which it is based to ensure dominant cutsets are captured.

The model maintenance process involves a periodic review and update cycle to model any changes in the plant design or operation. Plant hardware and procedure changes are reviewed to determine if they impact the internal events PRA and if a PRA modeling and/or documentation change is warranted. These reviews are documented. If any PRA changes are warranted they are added to the PRA configuration control (PRACC) database for PRA implementation tracking.

2.13.2.5.3 Comprehensive Critical Reviews

2.13.2.5.3.1 Background

To verify and improve the quality of the PRA model, reviews of the model have been performed to assess the development of the model against industry standards. In general, such reviews may be categorized in one of two categories:

1. Self-assessments, which are generally performed by members of the PRA group, sometimes with outside assistance and

2. Peer reviews, which are generally performed by qualified independent personnel outside the PRA group.

In either case, the reviewers use a documented process and guidance that specify expectations for technical capability in various areas. The reviewers document significant observations and recommendations, which are to be addressed, as appropriate, in future updates of the PRA. The following section focuses on the significant observations and recommendations from peer review and self assessments.

2.13.2.5.3.2 Westinghouse Owner's Group (WOG) PRA Peer Review

In 1999, the MPS3 internal events PRA received a formal industry PRA peer review. The purpose of the PRA peer review process was to provide a method for establishing the technical quality of a PRA for the spectrum of potential risk-informed plant licensing applications for which the PRA may be used. The PRA peer review process used a team composed of industry PRA consultants and utility peers, each with significant expertise in both PRA development and PRA applications. This review team provided both an objective review of the PRA technical elements and a subjective assessment, based on their PRA experience, regarding the acceptability of the PRA elements.

This review was performed using the WOG implementation of the industry PRA peer review methodology as defined in NEI-00-02, "PRA Peer Review Process Guidance." The review team reviewed over 200 attributes of 11 different elements of the PRA. Reviewer questions or comments that could not be answered during the review were documented in Fact & Observation (F&O) forms and were categorized by level of significance as follows:

A – Extremely important, technical adequacy may be impacted

B – Important, but may be deferred to next model update

C – Less important, desirable to maintain model flexibility and consistency with the industry

D – Editorial, minor technical item

S – Strength/Superior Treatment (no follow-up required)

The peer review is documented in the Westinghouse PRA peer review report (“Millstone Nuclear Power Station Unit 3 Probabilistic Risk Assessment Peer Review Report,” Westinghouse Owner’s Group, September 1999).

Fact and Observation (F&O) Summary

There were a total of 4 A level, 41 B level, and 59 C and D level F&Os. There were 11 F&Os that identified strengths. Subsequent to the peer review, the MPS3 internal events PRA model has been updated to address a majority of the F&Os. All A and B significance F&Os have been resolved and addressed in the PRA, as appropriate. Many of the C and D significance F&Os have also been addressed through model updates since the peer review. The outstanding resolution of the remaining C and D significance F&Os, which by definition are of lower priority, continues to be tracked for eventual resolution.

The forms for the A and B significance F&Os from the peer review report are provided at the end of Attachment A. The “Plant Response or Resolution” section of the form includes a discussion of how the F&O has been addressed.

2.13.2.5.3.3 MPS3 Internal Events PRA Self-assessment

In 2006, a self-assessment of the MPS3 internal events PRA against the ASME PRA Standard was completed by a team of experts from an independent PRA contractor with experience in performing NEI PRA Certifications and pre-Certification reviews. The assessment included a review of the Dominion PRA procedures, current model documentation notebooks as well as earlier model documentation.

The intent of the assessment was to provide a basic assessment of the current PRA against the ASME standard to determine if each of the requirements of Capability Category II of the Standard had been met and documented. The assessment team reviewed the technical adequacy of compliance with each of the requirements as compared to current PRA practices in the industry. Insights gained from recent industry programs to comply with the ASME Standard were also used.

All technical areas described in Section 4 of the ASME Standard were reviewed. Note that PRA Configuration Control, which is documented in Section 5 of the Standard, was not reviewed. As Dominion maintains PRAs for multiple power stations, the PRA update procedure is not specific to the MPS3 plant.

During this review, specific “Facts and Observations” (F&Os) were not generated. However, specific recommendations are provided for each Supporting Requirement (SR) that was assessed as not met by the current PRA model and documentation. These recommendations can be used directly to guide future PRA enhancement activities.

The review determined that over one-half of the SRs in each technical area of the Standard completely satisfy Category II requirements. Many of the “not met” requirements pertain to various documentation issues. In general, technical issues with the PRA that were identified have been largely identified in the previous peer review (e.g., inadequacies in the Level 2/LERF analysis, various accident sequence and human reliability analysis issues, and quantification issues, including the need for further sensitivity and uncertainty analyses).

An impact assessment was performed to determine which of those SRs that do not completely satisfy Category II requirements may have an impact on the model results for the SPU. A total of 30 SRs were assessed as having an impact on the results for the power uprate license application.

Attachment A contains the SRs in which the model and/or documentation were assessed as not meeting category II.

2.13.2.6 Results

The impact of the SPU is small for initiating event frequencies, component reliability, important systems and system functions, and Level 2/LERF, as modeled in the internal events at power PRA. The increase in the internal events (including flooding) CDF and LERF due to increases in initiator frequencies and operator action probabilities is as follows:

CDF Increase = 4.0E-07/yr

LERF Increase = 2.0E-08/yr.

No new vulnerabilities are introduced regarding fire and seismic event mitigation. Although no new vulnerabilities are introduced, the time available for operator actions decreased. However, the risk impact is considered to be small for these external events, based on insights from the IPE external events results.

During shutdown operations, there is a detailed process for managing plant risk that will continue to be used to maintain shutdown risk at a minimum when the SPU is implemented.

While this license amendment is not being requested as a risk-informed change, the risk increase is less than the 1.0E-06/yr CDF and 1.0E-7/yr LERF Category III criteria discussed in RG 1.174 (Reference 3). This would be considered a very small change in risk.

2.13.3 Conclusion

DNC has reviewed the assessment of the risk implications associated with the implementation of the proposed SPU and concludes that the potential impacts associated with the implementation are adequately modeled and/or addressed. DNC further concludes that the results of the risk analysis indicate that the risks associated with the proposed SPU are acceptable and do not create the “special circumstances” described in Appendix D of the Standard Review Plan, Chapter 19. Therefore, DNC finds the risk implications of the proposed SPU acceptable.

2.13.3.1 References

1. NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Use of Probabilistic Risk Assessment in Plant-Specific Risk-Informed Decision-Making: General Guidance, November 2002.

2. ASME RA-Sb-2005, Addenda to RA-S-2002, Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications.

3. NRC Regulatory Guide 1.174, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Rev 1, November 2002.

4. MPS3 Individual Plant Examination for Severe Accident Vulnerabilities, August 1990.

5. Computer Aided Fault Tree Analysis, CAFTA, version 5.2

6. NUREG/CR-4550, Analysis of Core Damage Frequency, 1990.

7. NUREG/CR-4896, Containment Loads Due to Direct Containment Heating and Associated Hydrogen Behavior: Analysis and Calculations with the Contain Code, May 1987.

8. NUREG/CR-6109, The Probability of Containment Failure by Direct Containment Heating in Surry, Sandia National Laboratories, 1995.

9. NUREG-1570, Risk Assessment of Severe Accident-Induced Steam Generator Tube Rupture, March 1998.

10. NUREG/CR-6075, The Probability of Containment Failure by Direct Containment Heating in Zion, 1994.

11. NUREG/CR-6338, Resolution of the Direct Containment Heating Issue for All Westinghouse Plants with Large Dry Containments or Subatmospheric Containments, 1996.

12. NUREG-1524, A Reassessment of the Potential for an Alpha-Mode Containment Failure and a Review of the Current Understanding of Broader Fuel-Coolant Interaction Issues, 1996.

13. NUMARC 91-06, “Guidelines for Industry Actions to Assess Shutdown Management”, December 1991.

14. MPS3 PRA Peer Review Report, prepared by Westinghouse as part of the Westinghouse Owners Group (WOG) PRA Peer Assessment, September 1999.

15. MPS3 PRA Model Notebook Part IV Appendix A.1 Revision 0, Internal Events Model Independent Assessment, August 2006.

16. RELAP 5/MOD3 Software Document File

17. MAAP 4, Modular Accident Analysis Program for LWR Power Plants, Computer Code Manual, 1994

18. NUREG/CR-5750, Rates of Initiating Events at US Nuclear Power Plants, 1987 – 1995, February 1999.

19. NUREG/CR-INEEL-04-02326, Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986 – 2003”, Draft report, October 2004.

20. EGG-SSRE-8875, Generic Component Failure Data Base for Light Water and Liquid Sodium Reactor PRAs”, EG&G Idaho, 1990

21. NUREG/CR-4639, Nuclear Computerized Library for Assessing Reactor Reliability, Rev. 4, 1994.

22. IEEE-STD-500, Guide to Reliability Data for Nuclear Power Generating Stations, Rev. 1, 1984.

23. NUREG/CR-5497, Common-Cause Failure Parameter Estimations, October 1998

Table 2.13.2.2.1.2-1 PRA Success Criteria Requiring Additional Thermal Hydraulic Analyses

Action	Event Tree/Function	Success Criteria
Bleed & Feed	Small LOCA Bleed and feed (BAF) Function	1 of 2 PORVs AND 1 of 4 high pressure safety injection (HPSI)/charging (CHG) pumps Initiate in 30 minutes
	Small-small LOCA, loss of seal cooling, steam generator tube rupture, Transient, loss of offsite power, loss of vital DC power, steam line break insider and outside containment BAF Function	1 of 2 PORVs AND 1 of 2 CHG pumps OR 2 of 2 PORVs AND 1 of 2 HPSI pumps Initiate in 30 minutes
Power Recovery during station blackout (SBO) or loss of service water (LOSW)	21 gpm reactor coolant pump (RCP) seal leak, turbine-driven auxiliary feedwater (TDAFW) Available	Recover power within 16.5 hrs.
	21 gpm RCP seal leak, TDAFW Failed	Recover power within 2.25 hrs.
	21 gpm RCP seal leak, TDAFW Available, PORV stuck open	Recover power within 1.75 hrs.
	21 gpm RCP seal leak, TDAFW Failed, PORV stuck open	Recover power within 1.25 hrs.
	182 gpm RCP seal leak, TDAFW Available	Recover power within 2.0 hrs.
	182 gpm RCP seal leak, TDAFW Failed	Recover power within 1.5 hrs.
SG Dryout	Loss of Main and Auxiliary feedwater (FW)	30 minutes to steam generator (SG) dryout

Table 2.13.2.2.1.3-1 Operator Actions Credited in the PRA

Basic Event	Description	Available Time	Human Error Probability	FV Importance
OAPADVBLOCK	Operators Fail To Close Block Valve To Isolate Stuck ADV	57 Minutes	3.9E-03	4.5E-05
OAPAFWVENT	Operators Fail To Provide Alternate Ventilation To The ‘A’ MDAFW Pump	212 Minutes	2.6E-01	5.2E-04
OAPAUXVENT	Operators Fail To Provide Alternate Ventilation To The Charging Pumps	18 Hours	2.6E-01	2.0E-02
OAPBAF	Operators Fail To Establish Bleed And Feed	27 Minutes	5.5E-02	1.4E-01
OAPCOND	Operators Fail To Establish Condensate Feed To SGs	60 Minutes	2.7E-02	Truncated
OAPDIRECTINJ	Operators Fail To Establish Direct Injection	205 Minutes	6.9E-02	1.2E-05
OAPEB	Operators Fail To Align Emergency Boration During Partial ATWS	597 Minutes	1.2E-04	2.3E-05
OAPESFAS	Operators Fail To Actuate Mitigating Equipment Following ESF Actuation System Failure	26 Minutes	7.9E-04	5.3E-05
OAPFPW	Operators Fail To Align Fire Water To CCE HX And Restore Charging Pumps	9.75 Hours	1.7E-02	1.7E-04
OAPHLR	Operators Fail To Establish Hot Leg Recirculation	538 Minutes	3.7E-04	2.9E-04
OAPISLOCADEP	Operators Fail To Depressurize RCS After ISLOCA	See Note 1	2.4E-02	6.1E-03
OAPISLOCAISOL	Operator Fails To Isolate ISLOCA After RCS Depressurization	See Note 1	6.4E-03	1.7E-03

Table 2.13.2.2.1.3-1 Operator Actions Credited in the PRA

Basic Event	Description	Available Time	Human Error Probability	FV Importance
OAPMANSCRAM	Operators Fail To Manually Scram The Reactor From The Control Room	60 Seconds	4.7E-04	1.5E-04
OAPMFW	Operators Fail To Re-Establish MFW/Condensate To SGs	35 Minutes	5.0E-02	3.4E-03
OAPPORVBLOCK	Operators Fail To Close PORV Block Fail To Isolate Stuck PORV	56 Minutes	2.7E-04	3.3E-06
OAPREC	Operators Fail To Establish Sump Recirculation (Large Or Medium LOCA)	9 Minutes	8.9E-03	6.3E-02
OAPRECS	Operators Fail To Establish Sump Recirculation (SLOCA Or SSLOCA)	126 Minutes	1.9E-04	1.5E-02
OAPSBODG	Operators Fail To Manually Start And Align The SBO Diesel	38 Minutes	4.4E-02	6.7E-02
OAPSGTR	Operators Fail To Refill RWST Given SGTR And Unisolable Faulted Steam Generator	575 Minutes	6.3E-03	9.7E-03
OAPSGTRRCSDEP	Operator Fails To Depressurize The RCS After A SGTR	See Note 1	1.6E-03	Truncated
OAPSGTRSGI	Operator Fails To Isolate Faulted SG During SGTR	See Note 1	9.8E-03	1.3E-03
OAPSTARTAFW	Operators Fail To Start The Affected AFW Pump Given Failure Of Auto	26 Minutes	1.0E-03	Truncated
OAPSTARTCHG	Operators Fail To Start Standby Charging Pump	28 Minutes	2.5E-03	3.7E-05
OAPTRIPLC	Operators Fail To Open Load Center Breakers That Power The MG Sets	50 Seconds	2.6E-03	7.1E-04

Table 2.13.2.2.1.3-1 Operator Actions Credited in the PRA

Basic Event	Description	Available Time	Human Error Probability	FV Importance
OAPTRIPRCP	Operators Fail To Trip RCP(S) In 13 Minutes Following Loss Of Seal Cooling	4.5 Minutes	1.6E-02	2.0E-03
OAPSWSTRAIN	Operators Fail To Align Standby SW Pump After Strainer Failure, Prior To Trip	See Note 1	5.0E-02	3.5E-06

Notes:

1. The CBDT method was used to obtain the cognitive error for these HEPs since the time available to perform these actions is long.

2. Note that the mean values of the HEPs do not strictly correlate with the available time. That is, actions with long available times do not necessarily mean the HEP will be smaller. The available time is only used by the HCR/ORE calculation of the cognitive error. Therefore, the cognitive error is generally governed by the CBDT method for actions with long available times.

Table 2.13.2.2.4-1 Summary of PRA Changes

PRA Element	Change	Pre-SPU	Post-SPU
Consequential small LOCA due to stuck open PORV	Increased PORV challenge probability by 10%	7.7E-02	8.5E-02
Loss of Offsite Power (LOOP)	Increased Plant-centered LOOP frequency by 10%	8.3E-03/yr	9.1E-03/yr
Transients	Increased general plant transient frequency by 10%	9.6E-01/yr	1.1E+00/yr
Offsite power recovery	Increased probability of offsite power non-recovery by 10% (see Note 1)	See table 2.13.2.2.4-2	
Operator action to establish bleed and feed	Increased probability by 10% (see Note 1)	4.9E-02	5.5E-02
Note 1 - The offsite power non-recovery probabilities and the probability of failure for the operator action to establish bleed and feed were confirmed to remain bounded by the SPU conditions in the thermal hydraulic analysis. Therefore, to estimate the CDF and LERF impact of changes to these probabilities, they were lowered by 10% for the pre-SPU case to estimate a "baseline" where the extra margin in these basic event probabilities is removed. That is, it is estimated that if the thermal hydraulic analyses were run until the core damage acceptance criteria is met that these probabilities would be lower by approximately 10% for the current core power level (i.e., pre-SPU).			

Table 2.13.2.2.4-2 Summary of LOOP Recovery Probabilities

LOOP	Recovery Time	Non-Recovery Probability Pre-SPU	Non-Recovery Probability Post-SPU
Grid Related	75 Minutes	4.6E-01	5.1E-01
	90 Minutes	3.9E-01	4.3E-01
	105 Minutes	3.3E-01	3.7E-01
	120 Minutes	2.9E-01	3.2E-01
	135 Minutes	2.5E-01	2.8E-01
	16.5 Hours	3.9E-03	4.3E-03
Plant-Centered	75 Minutes	1.4E-01	1.6E-01
	90 Minutes	1.3E-01	1.4E-01
	105 Minutes	1.2E-01	1.3E-01
	120 Minutes	1.1E-01	1.2E-01
	135 Minutes	1.0E-01	1.1E-01
	16.5 Hours	2.3E-02	2.5E-02
Weather Related	75 Minutes	8.7E-01	9.6E-01
	90 Minutes	8.5E-01	9.4E-01
	105 Minutes	8.2E-01	9.1E-01
	120 Minutes	7.9E-01	8.8E-01
	135 Minutes	7.6E-01	8.5E-01
	16.5 Hours	5.2E-02	5.8E-02

Table 2.13.2.2.4-3 Summary of CDF and LERF Impact

	Pre-SPU	Post-SPU	Increase
CDF (/yr)	6.2E-06	6.6E-06	4.0E-07
LERF (/yr)	5.2E-07	5.4E-07	2.0E-08

Table 2.13.2.2.4-4 CDF Impact by Initiator

Initiator	Pre-SPU CDF (/yr)	Post-SPU CDF (/yr)	CDF Increase (/yr)
Large LOCA	6.1E-08	6.1E-08	No Change
Medium LOCA	4.1E-07	4.1E-07	No Change
Small LOCA	5.3E-07	5.4E-07	7.0E-09
Small-Small LOCA	1.1E-07	1.1E-07	No Change
Loss of RCP Seal Cooling	1.0E-06	1.0E-06	2.0E-08
Instrument Tube LOCA	3.7E-08	3.7E-08	No Change
Steam Generator Tube Rupture	1.8E-07	1.8E-07	No Change
Inter-facing System LOCA	3.0E-07	3.0E-07	No Change
Loss of Offsite Power	2.4E-07	2.7E-07	2.7E-08
Station Blackout	1.4E-06	1.6E-06	1.6E-07
Loss of a DC Bus	1.3E-07	1.4E-07	1.0E-08
Loss of both DC Buses	5.3E-10	5.3E-10	No Change
General Transient	4.1E-07	4.5E-07	4.0E-08
Steam Line Break Inside Containment	8.4E-08	9.1E-08	7.3E-09
Steam Line Break Outside Containment	3.1E-07	3.6E-07	4.8E-08
ATWS	1.0E-06	1.1E-06	6.1E-08
Loss of Service Water	1.7E-09	1.7E-09	No Change
Flood	1.3E-07	1.4E-07	3.0E-09

Table 2.13.2.2.4-5 CDF Importance of Major Components and Operator Actions

Component	Pre-SPU		Post-SPU		Description
	FV	RAW	FV	RAW	
EDG A	2.1E-02	5.8	2.2E-02	6.0	DIESEL GENERATOR A FAILS TO START ON DEMAND
EDG B	2.1E-02	5.7	2.1E-02	5.8	DIESEL GENEATOR B FAILS TO START ON DEMAND
SBO Diesel	1.8E-02	2.3	1.9E-02	2.4	SBO DIESEL GENERATOR FAILS TO START ON DEMAND
Charging pump A	9.9E-03	7.3	9.5E-03	7.1	CHARGING PUMP 3CHS*P3A FAILS TO START
Charging pump B	9.6E-03	7.1	9.2E-03	6.9	CHARGING PUMP 3CHS*P3B FAILS TO START
MDAFW Pump A	5.2E-03	3.5	5.3E-03	3.5	MOTOR DRIVEN AUXILIARY FEEDWATER PUMP FWP1A FAILS TO START
MDAFW Pump B	5.2E-03	3.5	5.4E-03	3.6	MOTOR DRIVEN AUXILIARY FEEDWATER PUMP FWP1B FAILS TO START
TDAFW Pump	5.2E-02	6.4	5.4E-02	6.6	AFW TURBINE DRIVEN PUMP FW*P2 FAILS TO START
Operator Action - OACCONDBAF	5.4E-05	1.0	6.5E-05	1.0	OPERATORS FAIL TO PERFORM ACTIONS OAPCOND AND OAPBAF
Operator Action - OACMFWBAF	4.4E-02	5.6	4.5E-02	5.7	OPERATORS FAIL TO PERFORM ACTIONS OAPMFW AND OAPBAF
Operator Action - OACSGTRSGIDEP	1.0E-02	8.1	9.4E-03	7.7	OPERATOR FAILS TO PERFORM ACTIONS OAPSGTRSGI AND OAPRCSDEP
Operator Action - OACSTRTCHGESFAS	2.7E-04	3.1	2.6E-04	3.0	OPERATORS FAIL TO PERFORM ACTIONS OAPSTARTCHG AND OAPESFAS
Operator Action - OACTRPRCPSTRTCHG	1.4E-04	1.2	1.3E-04	1.2	OPERATORS FAIL TO PERFORM ACTIONS OAPTRIPRCP AND OAPSTARTCHG
Operator Action - OAPADVBLOCK	4.2E-05	1.0	4.9E-05	1.0	OPERATORS FAIL TO CLOSE BLOCK VALVE TO ISOLATE STUCK ADV

Table 2.13.2.2.4-5 CDF Importance of Major Components and Operator Actions

Component	Pre-SPU		Post-SPU		Description
	FV	RAW	FV	RAW	
Operator Action - OAPAFWVENT	4.7E-04	1.0	5.2E-04	1.0	OPERATORS FAIL TO PROVIDE ALTERNATE VENTILATION TO THE 'A' MDAFW PUMP
Operator Action - OAPAUXVENT	2.0E-02	1.1	2.0E-02	1.1	OPERATORS FAIL TO PROVIDE ALTERNATE VENTILATION TO THE CHS/CCP PUMPS
Operator Action - OAPBAF	1.3E-01	3.4	1.3E-01	3.3	OPERATORS FAIL TO ESTABLISH BLEED AND FEED
Operator Action - OAPDIRECTINJ	1.3E-05	1.0	1.3E-05	1.0	OPERATORS FAIL TO ESTABLISH DIRECT INJECTION
Operator Action - OAPEB	2.3E-05	1.2	2.4E-05	1.2	OPERATORS FAIL TO ALIGN EMERGENCY BORATION
Operator Action - OAPESFAS	5.5E-05	1.1	5.2E-05	1.1	OPERATORS FAIL TO ACTUATE MITIGATING EQUIPMENT FOLLOWING ESFAS FAILURE
Operator Action - OAPFPW	1.7E-04	1.0	1.7E-04	1.0	OPERATORS FAIL TO ALIGN FIRE WATER TO CCE HX AND RESTORE CHS PUMP
Operator Action - OAPHLR	3.0E-04	1.8	2.8E-04	1.8	OPERATORS FAIL TO ESTABLISH HOT LEG RECIRCULATION
Operator Action - OAPISLOCADEP	6.4E-03	1.3	6.0E-03	1.3	OPERATORS FAIL TO DEPRESSURIZE RCS AFTER ISLOCA
Operator Action - OAPISLOCAISOL	1.8E-03	1.3	1.7E-03	1.3	OPERATOR FAILS TO ISOLATE ISLOCA AFTER RCS DEPRESSURIZATION
Operator Action - OAPMANSCRAM	1.6E-04	1.3	1.5E-04	1.3	OPERATORS FAIL TO MANUALLY SCRAM THE REACTOR FROM THE CONTROL ROOM
Operator Action - OAPMFW	3.6E-03	1.1	3.4E-03	1.1	OPERATORS FAIL TO RE-ESTABLISH MFW/COND TO SGs
Operator Action - OAPPORVBLOCK	3.4E-06	1.0	3.9E-06	1.0	OPERATORS FAIL TO CLOSE PORV BLOCK FAIL TO ISOLATE STUCK PORV

Table 2.13.2.2.4-5 CDF Importance of Major Components and Operator Actions

Component	Pre-SPU		Post-SPU		Description
	FV	RAW	FV	RAW	
Operator Action - OAPREC	6.5E-02	8.2	6.1E-02	7.8	OPERATORS FAIL TO ESTABLISH SUMP RECIRCULATION (LARGE OR MEDIUM LOCA)
Operator Action - OAPRECS	1.6E-02	81.9	1.5E-02	77.3	OPERATORS FAIL TO ESTABLISH SUMP RECIRCULATION (SLOCA OR SSLOCA)
Operator Action - OAPSBODG	6.3E-02	2.4	6.7E-02	2.4	OPERATORS FAIL TO MANUALLY START AND ALIGN THE SBO DIESEL
Operator Action - OAPSGTR	1.0E-02	2.6	9.4E-03	2.5	OPERATORS FAIL TO REFILL RWST GIVEN SGTR AND UNISOLABLE FAULTED STEAM GENERATOR
Operator Action - OAPSGTRSGI	1.3E-03	1.1	1.2E-03	1.1	OPERATOR FAILS TO ISOLATE FAULTED SG DURING SGTR
Operator Action - OAPSTARTCHG	3.8E-05	1.0	4.1E-05	1.0	OPERATORS FAIL TO START STANDBY CHARGING PUMP
Operator Action - OAPSWSTRAIN	3.6E-06	1.0	3.4E-06	1.0	OPERATORS FAIL TO ALIGN STNDBY SW PUMP AFTER STRAINER FAILURE, PRIOR TO TRIP
Operator Action - OAPTRIPLC	7.3E-04	1.3	7.5E-04	1.3	OPERATORS FAIL TO OPEN LOAD CENTER BREAKERS THAT POWER THE MG SETS
Operator Action - OAPTRIPRCP	2.1E-03	1.1	2.0E-03	1.1	OPERATORS FAIL TO TRIP RCP(S) IN 13 MIN FOLLOWING LOSS OF SEAL COOLING
Offsite Power Recovery - OSPRGR090	1.1E-03	1.0	1.2E-03	1.0	FAILURE TO RECOVER GR LOOP - PORVs AVAIL, SGC FAILS (182 GPM PER RCP)
Offsite Power Recovery - OSPRGR105	1.2E-03	1.0	1.3E-03	1.0	FAILURE TO RECOVER GR LOOP - STUCK PORV, SGC AVAIL (21 GPM PER RCP)
Offsite Power Recovery - OSPRGR120	7.0E-02	1.2	7.3E-02	1.2	FAILURE TO RECOVER GR LOOP - PORVs AVAIL, SGC AVAIL (182 GPM PER RCP)

Table 2.13.2.2.4-5 CDF Importance of Major Components and Operator Actions

Component	Pre-SPU		Post-SPU		Description
	FV	RAW	FV	RAW	
Offsite Power Recovery - OSPRGR135	3.9E-03	1.0	4.1E-03	1.0	FAILURE TO RECOVER GR LOOP - PORVs AVAIL, SGC FAILS (21 GPM PER RCP)
Offsite Power Recovery - OSPRGR990	1.4E-02	4.6	1.4E-02	4.4	FAILURE TO RECOVER GR LOOP - PORVs AVAIL, SGC AVAIL (21 GPM PER RCP)
Offsite Power Recovery - OSPRPC090	3.4E-05	1.0	4.2E-05	1.0	FAILURE TO RECOVER PC LOOP - PORVs AVAIL, SGC FAILS (182 GPM PER RCP)
Offsite Power Recovery - OSPRPC105	4.1E-05	1.0	5.2E-05	1.0	FAILURE TO RECOVER PC LOOP - STUCK PORV, SGC AVAIL (21 GPM PER RCP)
Offsite Power Recovery - OSPRPC120	7.8E-03	1.1	9.1E-03	1.1	FAILURE TO RECOVER PC LOOP - PORVs AVAIL, SGC AVAIL (182 GPM PER RCP)
Offsite Power Recovery - OSPRPC135	2.7E-04	1.0	3.6E-04	1.0	FAILURE TO RECOVER PC LOOP - PORVs AVAIL, SGC FAILS (21 GPM PER RCP)
Offsite Power Recovery - OSPRPC990	2.6E-02	2.1	3.0E-02	2.2	FAILURE TO RECOVER PC LOOP - PORVs AVAIL, SGC AVAIL (21 GPM PER RCP)
Offsite Power Recovery - OSPRWR090	2.0E-04	1.0	2.3E-04	1.0	FAILURE TO RECOVER WR LOOP - PORVs AVAIL, SGC FAILS (182 GPM PER RCP)
Offsite Power Recovery - OSPRWR105	2.8E-04	1.0	3.2E-04	1.0	FAILURE TO RECOVER WR LOOP - STUCK PORV, SGC AVAIL (21 GPM PER RCP)
Offsite Power Recovery - OSPRWR120	2.6E-02	1.0	2.8E-02	1.0	FAILURE TO RECOVER WR LOOP - PORVs AVAIL, SGC AVAIL (182 GPM PER RCP)
Offsite Power Recovery - OSPRWR135	1.4E-03	1.0	1.5E-03	1.0	FAILURE TO RECOVER WR LOOP - PORVs AVAIL, SGC FAILS (21 GPM PER RCP)
Offsite Power Recovery - OSPRWR990	2.6E-02	1.5	2.8E-02	1.5	FAILURE TO RECOVER WR LOOP - PORVs AVAIL, SGC AVAIL (21 GPM PER RCP)
PORV 455A	8.0E-03	3.9	8.1E-03	4.0	PORV 455A FAILS TO RECLOSE
PORV 455A	5.5E-04	1.2	5.2E-04	1.2	PORV 455A FAILS TO OPEN

Table 2.13.2.2.4-5 CDF Importance of Major Components and Operator Actions

Component	Pre-SPU		Post-SPU		Description
	FV	RAW	FV	RAW	
PORV 456	8.4E-03	4.1	8.5E-03	4.1	PORV 456 FAILS TO RECLOSE
PORV 456	5.4E-04	1.2	5.1E-04	1.2	PORV 456 FAILS TO OPEN
RHS/LPSI pump A	4.2E-05	1.0	4.0E-05	1.0	MOTOR DRIVEN RESIDUAL HEAT REMOVAL PUMP RHP1A FAILS TO START ON DEMAND
RHS/LPSI pump B	3.6E-05	1.0	3.4E-05	1.0	MOTOR DRIVEN RESIDUAL HEAT REMOVAL PUMP RHP1B FAILS TO START ON DEMAND
RSS pump A	3.6E-05	1.0	3.4E-05	1.0	RECIRCULATION SPRAY PUMP 3RSS*P1A FAILS TO START
RSS pump C	3.2E-05	1.0	3.0E-05	1.0	RECIRCULATION SPRAY PUMP RSS*P1C FAILS TO START
RSS pump B	2.6E-05	1.0	2.4E-05	1.0	RECIRCULATION SPRAY PUMP 3RSS*P1B FAILS TO START
RSS pump D	2.5E-05	1.0	2.3E-05	1.0	RECIRCULATION SPRAY PUMP RSS*P1D FAILS TO START
SIH pump A	1.0E-02	6.8	9.9E-03	6.5	MOTOR DRIVEN SAFETY INJECTION PUMP A FAILS TO START
SIH pump B	9.3E-03	6.2	8.9E-03	6.0	MOTOR DRIVEN SAFETY INJECTION PUMP B FAILS TO START
SW pump A	6.9E-05	1.0	7.0E-05	1.0	SERVICE WATER PUMP SWP1A FAILS TO START ON DEMAND
SW pump C	6.9E-05	1.0	7.0E-05	1.0	SERVICE WATER PUMP SWP1C FAILS TO START ON DEMAND
SW pump B	6.0E-05	1.0	6.1E-05	1.0	SERVICE WATER PUMP SWP1B FAILS TO START ON DEMAND
SW pump D	6.0E-05	1.0	6.1E-05	1.0	SERVICE WATER PUMP SWP1D FAILS TO START ON DEMAND

Table 2.13.2.5.1.1-1 MPS3 INTERNAL EVENTS PRA INITIATING EVENTS

Event ID	Description	Discussion
LLOCA	Large loss of coolant accident (LOCA)	A large LOCA is defined as a break in the reactor coolant system (RCS) boundary in the range of > 6"- 27" equivalent diameter. The lower bound is the minimum break size that will cause rapid depressurization such that the Accumulators and either 1 of 2 low head safety injection (SIL) pumps or 2 of 4 high pressure safety injection (SIH) or charging pumps will provide adequate core cooling.
MLOCA	Medium LOCA	A medium LOCA is defined as a break in the RCS boundary in the range of 2" to 6". The loss of coolant will lead to a slower depressurization than in the case of the large LOCA, but as the break is large enough for all decay heat to be dissipated, secondary heat removal is not essential in order to prevent core damage. The accumulators and a high head safety injection pump or a charging pump is required for core cooling.
SLOCA SSLOCA	Small LOCA Small-Small LOCA	The small LOCA break size includes breaks from 2" down to 1”. A small break LOCA is not capable of removing all the decay heat following reactor trip (on low pressurizer pressure and the generation of the SI signal), therefore reactor pressure will remain high. Since all decay heat is not being removed through the break, auxiliary feedwater (AFW) is required following the trip of the main feedwater (MFW) by the SI signal, or feed and bleed is utilized if AFW is unavailable. Small-small LOCAs (SSLOCA) are also modeled for breaks in lines that are less than 1.” SSLOCAs do not cause a containment depressurization actuation (CDA).
LOOP	Loss of offsite power	Interruption of normal AC power supply to the plant.
LMFW	Loss of MFW	Events cause a loss of MFW. Recovery of MFW is not possible.
GPT	General plant transient with MFW available	Various routine/anticipated transients that would result in a reactor trip and would require a similar response from plant systems. Example events would include reactor/turbine trips, loss of RCS flow and steam/feedwater mismatches.

Table 2.13.2.5.1.1-1 MPS3 INTERNAL EVENTS PRA INITIATING EVENTS

Event ID	Description	Discussion
LOSC	Loss of reactor coolant pump (RCP) seal cooling	Loss of reactor plant component cooling water (RPCCW) flow to the RCP seals concurrent with a loss of charging flow for RCP seal injection.
LVDCAB	Loss of one vital DC bus A or B	Failure of 125V DC bus 301A-1 or 301B-1, one pressurizer power operated relief valve (PORV), and half of all engineered safety features (ESF) equipment.
LVDC	Loss of both vital DC buses	Failure of both 301A-1 and 301B-1 vital DC buses results in a complete loss of control power to both trains of the ESF systems and both PORVs.
LOSW	Loss of service water (SW)	Loss of service water affects many frontline and support systems in the plant – SIH pump coolers, charging pump coolers (needed only when Auxiliary Building temperatures are high), Recirculation Spray heat exchangers, EDG coolers, RPCCW, turbine plant CCW. This event tree considers the credible risks of loss of SW, including the potential for a loss of RCP seal cooling.
SGTR	Steam generator tube rupture	Primary-to-secondary leakage/ruptures in the steam generator tube region.
ATWS	Anticipated transient without scram (ATWS)	Transient events that experience a failure of the control rods to insert following the generation of a reactor trip signal. Reactor trip failures include both electrical failure of the reactor protection system (RPS) and mechanical failure due to control rod binding.
SLBI	Steamline break inside containment	In general the consequences of a major steam leak are mitigated by steam line isolation, Main feedwater isolation, boration with the charging pumps, and reactor trip.
SLBO	Steam line break outside containment	The event differs from the steam line break inside containment because: 1) it is necessary to isolate all steam generators (SGs), and 2) failure of the Main feedwater and Condensate systems.

Table 2.13.2.5.1.1-1 MPS3 INTERNAL EVENTS PRA INITIATING EVENTS

Event ID	Description	Discussion
ITLOCA	Instrument tube LOCA	A rupture of an in-core instrument tube would be similar to a SSLOCA accident. However, the inventory lost through the break would accumulate within the reactor cavity, not in the containment sump. Thus, the potential exists for the recirculation spray pumps to be damaged by drawing suction from an empty containment sump.
SBO	Station blackout	A loss of offsite power with failure of the EDGs results in a total loss of electrical power. The turbine driven auxiliary feedwater pump (TDAFW) is the only means of decay heat removal. Given that AC power has failed, the charging, service water, and component cooling water systems are disabled, and RCP seal leakage is imminent.
ISLOCA	Interfacing Systems LOCA outside containment	A break can occur in the piping outside containment, and therefore no possibility will exist for recirculation when the Refueling Water Storage Tank (RWST) is depleted.

Table 2.13.2.5.2-1 MPS3 Model Change History

Date	Model Change
1990	Submittal of IPE
1992	NRC staff evaluation report concludes IPE meets the intent of Generic Letter 88-20.
1995	Model converted from support state to linked fault tree methodology Ventilation dependency explicitly modeled DC power dependency explicitly modeled Total loss of service water initiator modeled
1996	LERF model developed using original Plant Safety Study model
1998	Station Blackout (SBO) diesel generator battery limitation modeled Transfer to sump recirculation analyzed using simulator data Plant-specific data update
1999	Time-dependent SBO model incorporated Loss of ventilation/room heat-up calculation conclusions incorporated
1999	Westinghouse Owner's Group peer review completed
2000	Incorporated loss of offsite power and offsite power restoration calculations
2002	NUREG/CR-5750 used as source of general initiating event frequencies Incorporated some of the peer review level A and B F&Os
2004	Added main feedwater and condensate systems to the secondary cooling function.
2005	MSPI Model Update completed a) plant specific data b) reliability: 01/01/2000-12/31/2004 c) unavailability: January, 2002 to December, 2004 d) initiating events: 1990 to 12/31/2004 e) addressed remaining A and B level peer review F&Os

Table 2.13.2.5.2-1 MPS3 Model Change History

Date	Model Change
2006	2005 Mod A Model (M305 mod A) a) revised the cooling dependency for the Charging pump oil cooling system (CCE). SW is not required to cool Charging pumps if auxiliary building temperatures remain below 90F.
2006	2005 Mod B and C Model (M305 mod B & C) a) added internal flooding in mod B b) revised junction box flood damage logic in internal flooding model in mod C
2007	2005 Mod D Model (M305 mod D) a) added hot leg recirculation to large LOCA b) added new pre-initiator HEPs c) updated HRA using latest methodology (CBDT, HCR, THERP) d) updated interfacing system LOCA e) updated level 2 f) various other changes (e.g. replaced logic that assumed LOCA, SGTR or SLB occurs in one RCS loop or SG).

Attachment A
PRA Model Reviews

A.1 PRA Model Reviews

This attachment includes the results of two model reviews:

- Westinghouse Owners Group (WOG) PRA Peer Review (Reference 14)
- Independent self-assessment against the ASME PRA standard (Reference 15)

A.1.1 WOG PRA Peer Review

To verify and improve the quality of the PRA model, reviews have been performed to assess the development of the model against industry standards. The first major model review was performed in 1999 by the Westinghouse Owner's Group. The review was performed in accordance with the peer review methodology defined in NEI 00-02, PRA Peer Review Process Guidance. A group of industry PRA experts and peers reviewed the 11 different elements of the PRA. Reviewer questions or comments that could not be answered during the review were documented in Fact & Observation (F&O) forms and were categorized by level of significance as follows:

A – Extremely important, technical adequacy may be impacted

B – Important, but may be deferred to next model update

C – Less important, desirable to maintain model flexibility

D – Editorial, minor technical item

S – Strength/Superior Treatment (no follow-up required)

The peer review is documented in the Westinghouse PRA peer review report (Reference 14). There were a total of 4 A level, 41 B level, and 59 C and D level F&Os. There were 11 F&Os that identified strengths. The A and B level F&Os and their resolutions are included in Section A.2.1.

A.1.2 Independent self-assessment Against ASME PRA Standard

An independent review of the MPS3 PRA model, data and documentation was performed in 2006 to assess the model against the Category II requirements of the current ASME Standard for PRA, including Addenda B (Reference 2). The review was conducted by a team of experts with experience in performing NEI PRA Certifications and pre-Certification reviews. The assessment included a review of the Dominion PRA procedures, current model documentation notebooks as well as earlier model documentation.

The intent was to provide a basic assessment of the current PRA against the ASME standard to determine if each of the requirements of Capability Category II of the Standard had been met and documented. The assessment team reviewed the technical adequacy of compliance with each of the requirements as compared to current PRA practices in the industry. Insights gained from recent industry programs to comply with the ASME Standard were also used.

All technical areas described in Section 4 of the ASME Standard were reviewed. Note that PRA Configuration Control, which is documented in Section 5 of the Standard, was not reviewed. As Dominion maintains PRAs for multiple power stations, the PRA configuration control procedure is not specific to the MPS3 plant.

During this review, specific F&Os were not generated. However, specific recommendations are provided for each Supporting Requirement (SR) that was assessed as not met by the current PRA model and documentation. These recommendations can be used directly to guide future PRA enhancement activities.

The review determined that over one-half of the SRs in each technical area of the Standard completely satisfy Category II requirements. Many of the "not met" requirements pertain to various documentation issues. In general, technical issues with the PRA that were identified have been largely identified in the previous peer review (e.g., inadequacies in the Level 2/LERF analysis, various accident sequence and human reliability analysis issues, and quantification issues, including the need for further sensitivity and uncertainty analyses).

An impact assessment was performed to determine which of those SRs that do not completely satisfy Category II requirements may have an impact on the model results for the SPU. A total of 30 SRs were assessed as having an impact on the results for the power uprate license application. Section A.2.2 contains these 30 SRs and their resolutions. The model was revised in 2007 to address these SRs. This model was used in the risk evaluation of the SPU.

A.2 Model Review Results

Section 2.1 includes the A and B level F&Os from the WOG peer review. Section 2.2 contains the ASME supporting requirements that were not met that were determined to impact the model results for the SPU.

A.2.1 WOG Peer Review A and B Level F&Os

The following are the WOG peer review A and B level F&Os and their resolution documented in the Plant Response or Resolution section of the form.

Fact/Observation Regarding PRA Technical Elements

Observation (ID: IE-1)/Element IE/Subelement 1, 3

While the initiating event selection and grouping methodology used in the original PSS appears sound and is adequately documented, there is no guidance for how these activities should be updated, or how reviews of plant operating experience (or updates of the previous reviews) should be performed. This is inconsistent with other aspects of the PRA process, which are already proceduralized.

Level of Significance

B

Possible Resolution

Develop guidance document, similar to other existing procedures, reflecting current methods for IE identification and grouping and the periodic review of operating experience to ensure that previous IE analyses remain valid. This will ensure that this aspect of PRA updating is put on “equal footing” with the other aspects of the PRA update, which are already proceduralized.

Plant Response or Resolution

Guidance for IE identification and grouping and the periodic review of operating experience has been developed and is documented in PRA Manual Part II Chapter A Section 1 [NB01] and Part IV Chapter A [NB02].

As part of the quality review for the SPU, a systematic review of initiating events was performed to verify the appropriateness of the initiators included in the model. The review confirmed the existing initiators were appropriate, but also recommended additional investigation of some initiators to determine if they should be developed separately. The following initiators were recommended to be reviewed further:

- Loss of single or multiple 120V Vital AC buses and panels
- Loss of single or multiple 125V DC panels
- Loss of single or multiple 4KV or 480V AC buses
- Loss of Control Room HVAC
- Loss of Reactor Plant HVAC System
- Loss of Charging

Further investigation and sensitivities will be performed to determine which of these initiators should be modeled separately. The results of the current model are considered acceptable in terms of evaluating the impact of the SPU since the model already includes these dependencies in the fault trees. Plus, since the risk evaluation of the SPU is focused on the change in CDF and LERF, the addition of the above initiators is not anticipated to change the conclusions.

Fact/Observation Regarding PRA Technical Elements

Observation (ID: IE-1)/Element IE/Subelement 1, 3

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: IE-2)/Element IE /Subelement 4, 11, 19, 20
The current PRA relies on the initiating event identification and grouping analysis that was performed in the PSS. That analysis seems to be thorough. However, there is no documentation to indicate that this initial set of selected initiators was reviewed against more recent plant/industry experience for completeness. Since the time of the PSS, several initiators have been added, and several have been deleted. But evidence of a systematic review is lacking.
Level of Significance
B The current list of initiators evaluated in the PRA seems reasonable. But, a periodic review to determine if changes are needed is warranted.
Possible Resolution
Verify that grouping and subsuming assumptions in PSS remain valid today. Document results to demonstrate this. Provide documentation for any changes from the original PSS analysis.
Plant Response or Resolution
In 2005, Dominion performed a fleet-wide review of initiating events and their groupings. Out of this review, the PRA model notebooks for initiating events were re-organized to document the identification and grouping of initiating events, which is documented in the IE.1 notebooks [NB03], and the quantification of the initiating events, which is documented in the IE.2 notebooks [NB04].

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: IE-4)/Element IE; SY/Subelement IE-10; SY-21
A documented structured approach for support system Initiating Event selection should be included. A number of support system initiators were considered in the PSS and a systematic approach was used. The current PRA has added and deleted various events, but a structured approach was not used.
Level of Significance
B
Possible Resolution
The development of a dependency matrix of support system Initiating Events vs. affected/required plant systems would be an acceptable method of documenting a systematic review.
Plant Response or Resolution
The IE.1 model notebook [NB03] was developed in 2005 to document the identification and grouping of initiators for the model. During the development of the notebook, a systematic approach was used along with input from the PSS. A dependency matrix was developed to show the dependency of the front line and support systems, which is also included in the IE.1 notebook.

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: IE-7)/Element IE/Subelement IE-5
The argument provided for screening out loss of HVAC initiators is not convincing, for the following reasons. • Loss of an active system is a relatively high frequency event (redundancy argument is not good for normally-running systems which have to operate all the time. • Operator action time windows are based not only on tech specs but time to thermal damage of components, which is uncertain. • HRA of actions based on off-normal procedures might not result in low human error probabilities. • If Loss of switchgear ventilation is a concern in 24 hours after an accident, it could be important as an initiator (e.g., as was found in Beaver Valley, STP, TMI-2, Diablo Canyon). • The argument is whether or not a quantification is justified, not what the result will be. • Other plants that have found important contributors from reactor trip followed by loss of HVAC have generally found comparably important support system initiating events (e.g., as was the case with Beaver Valley, STP, TMI-1)
Level of Significance
B
Possible Resolution
Add appropriate initiating events for these initiators or provide a more thorough evaluation in the PRA as to why they need not be modeled.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: IE-7)/Element IE/Subelement IE-5 (continued)
Plant Response or Resolution
Based on Tech Eval M3-EV-99-0114 [CALC01], the total nominal heat removal requirement for the East Switchgear Room is 81 kW. From Calc File S-01759S3 [CALC02], the maximum temperature in the East Switchgear Room during the 24-hour PRA mission time for a nominal heat load of 85 kW is 118.54°F, which is below the EQ temperature of 120°F. Note that the East Switchgear Room bounds the West Switchgear Room. Therefore, ventilation is not required in the Switchgear Rooms for the 24-hour mission time, and no initiating event for loss of ventilation in the Switchgear Rooms should be included in the MPS3 PRA Model. As shown by the GOTHIC room heat-up calculations for the ESF Building ECCS pump rooms (ERC 25212-ER-04-0001 [CALC03]), a loss of ventilation in the rooms containing the Safety Injection, Residual Heat Removal, Quench Spray, and Recirculation Spray pumps would not result in the failure in any of these pumps or their associated equipment. Similarly, the GOTHIC calculations showed that the equipment in the Mechanical Equipment Rooms, as well as the Terry Turbine and MDAFW Pump 'B' rooms, would not fail as a result of loss of ventilation in those areas. The only area that would significantly exceed the EQ temperature in the ESF Building if ventilation fails is the MDAFW Pump 'A' room. Failure of the 'A' MDAFW pump can be prevented by a opening the exterior door to the MDAFW Pump 'A' room within 4 hours. Failure of ventilation in these areas would not result in a Reactor Trip or an event of any kind, since the only pump that would fail is the 'A' MDAFW pump, which would not cause a trip. Also, if the plant has not tripped, the AFW pumps would not be running, so the heat load would be much lower in those rooms, and the temperature in the rooms would not reach the EQ temperature anyway. As shown by the GOTHIC room heat-up calculations for the Intake Structure SW Cubicles (ERC 25212-ER-04-0001), a loss of ventilation in one of the SW Cubicles would not result in failure of the SW pumps. Ventilation is removed from the MPS3 PRA Model as a support system for the SW pumps. Also, loss of ventilation in the SW Cubicles is not an initiating event, since the plant would not trip, and SW would not be lost. The MPS3 PRA model was revised in the 2005 model update to remove the ventilation dependencies from these pumps.

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: IE-8)/Element IE/Subelement 8
NU has performed a thorough review of plant operating history to determine if new initiators should be considered. However, no documentation of a review of industry events was provided in the PRA.
Level of Significance
B
Possible Resolution
Perform a review of industry operating experience for similar plants and document the results of that review in the data update calculation. Evaluate any new initiators for applicability to MPS3.
Plant Response or Resolution
The IE.1 model notebook [NB03] was developed in 2005 to document the identification and grouping of initiators for the model. During the development of the notebook, a systematic approach was used along with input from the PSS. Also, industry OE is reviewed for impact on the model and added to the PRA configuration control database. PRA Manual Part IV chapter A [NB02] provides guidance for review of plant design changes and OE.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: IE-10)/Element IE; DE/Subelement IE-17; DE-5
It appears that each initiating event is quantified properly. However, there is not a traceable basis for how the quantification method for each initiating event frequency was determined.
Level of Significance
B
Possible Resolution
A description of the approach used to determine the quantification technique (use of industry data, FMEA, system initiator fault tree, etc.) selected as the most appropriate for each initiator should be provided in the PRA.
Plant Response or Resolution
PRA notebook IE.2 [NB04] contains details on the quantification of the initiating events. Guidance for IE quantification has been developed and is documented in PRA Manual Part II Chapter A Section 2 [NB01].

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: IE-12)/Element IE/Subelement IE-5
The inclusion of common cause failures of the normally running service water pumps as an initiating event is indicative of a thorough search for initiating events. However, the quantification of the initiating event frequency using generic estimates of the common cause factors is inadequate for such a high-risk contributor. Such high contributions to CDF or LERF from events that have been quantified should be followed by a detailed quantification that takes into account plant specific factors. In addition, a recovery factor was applied that was not supported by a detailed HRA. It is acknowledged that NU has taken steps to evaluate possible design modifications that would be helpful to mitigate the consequences of an interruption of service water flow.
Level of Significance
B
Possible Resolution
Perform a screening of the industry events used to determine the common cause factors and complete a detailed CCF analysis consistent with NUREG/CR-4780 or their more recent counterparts by INEEL. Once the design modifications to reduce vulnerability to loss of service water are implemented, update the model including an appropriate HRA of any credited recovery actions.
Plant Response or Resolution
The CCF analysis was revised and detailed HRAs were performed for the recovery factors in the M3021001 model. In the 2005 model update, the reliability, unavailability and CCF data were updated along with changes to the SW dependency of the Charging pumps (SW not required if Aux Bldg temperatures are maintained). With the change in the Charging pump SW dependency, the LOSW CDF contribution was reduced significantly.

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: AS-1)/Element AS/Subelement 17, 18, 22
The success criteria and associated bases, including the definition of core damage, that were used to develop the event tree logic were originally developed in the PSS. While the SBO Coping Studies used an acceptable definition of core damage (Peak core temperatures > 2200° F) those bases are not always clearly stated in the documentation of the current PSA update, e.g., the event tree calculation files. It is not clear that a consistent definition of core damage was used to develop all the success criteria and operator time windows.
Level of Significance
B or C
Possible Resolution
The MPS3 PRA team should consider adopting an industry accepted definition of core damage for future updates, such as core exit temperatures > 1200° F. Preferably the definition should correspond to some observable measurement or quantity that the operators can determine so that the tie in to the HRA time windows is clear and specific. All the event sequence development success criteria and time windows should refer to one consistent core damage definition. If success criteria from the original PSS are continued to be used, their relationship to the adopted core damage definition needs to be understood. This point is emphasized in the ASME PRA standard, Draft 10 and 11 on the Success Criteria Element.
Plant Response or Resolution
The AS.1 and SC.1 notebooks [NB05 and NB06] were revised (revision 1 for both) to contain what is assumed for core damage (CET > 1200F). Also, the discussion on key assumptions in Part 2 of the model notebook [NB01] contains some additional information on the sensitivity of success criteria for different definitions of core damage.

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: AS-4)/Element AS/Subelement 9, 23
While the 24 hour mission time is generally used, there are examples where it is bypassed. In an earlier version of the SBO event tree, there was a top event “MIT” to capture the functions of mitigating the RCP seal LOCA after electric power recovery was a success. In the most recent update this function was not included, so there seem to be successfully terminated sequences where there is a seal LOCA initiated, AC is restored, and the mission time for LOCA mitigation is truncated at the time of successful recovery. This assumption is optimistic but probably does not impact the CDF calculation in a significant way.
Level of Significance
B
Possible Resolution
It is recommended that for Seal LOCA sequences the mission time for successful mitigation be carried out at least until the leak rate is essentially eliminated via RCS depressurization, or at least 24 hours. Otherwise provide justification why the omission of seal LOCA mitigation does not significantly impact the results. In general, for scenarios in which equipment support functions are recovered, allowing the equipment to be re-started and run, the potential for failure to re-start and failure to run for the entire mission time should be evaluated.
Plant Response or Resolution
To mitigate a SBO event once offsite AC power is recovered (or a total LOSW event in conjunction with a loss of room cooling in the Auxiliary Building, following recovery of ECCS injection) would require 1 of 4 HPSI/Charging pumps. The probability of failure of all of these pumps (assuming average maintenance unavailabilities) is on the order of 1E-03. Thus, the contribution to CDF of all SBO events would be increased by about 0.1%, and SBO events contribute about 6% to CDF, so the increase in CDF would be about 0.006%. This increase in CDF is considered to be negligible. Therefore, failure to recover ECCS injection is not included in the PRA Model.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: AS-8)/Element AS/Subelement 5, 19
There is only indirect evidence available to verify that intentional decisions were made and actions taken to ensure PSA model is consistent with the current plant configuration. The calculations are signed off, which implies the models were approved by cognizant personnel as representing the as-built, as-operated plant. This would be made more clear if the documentation for the PSA event sequence model included a design freeze date, and a data cutoff date. The fact that the models and assumptions have been validated against the current design and procedures could thereby be made more explicit.
Level of Significance
B
Possible Resolution
Add design freeze date and validate the models against recent plant mods and procedure changes.
Plant Response or Resolution
The PRA group receives every implemented design change per the Millstone Design Control Manual. The PRA group is also on distribution for every plant procedure change. Any potentially impacting design change or procedure change is placed into a PRA configuration database and prioritized for the model updates. A freeze date for design and procedure changes is not included in the model since these changes may not be incorporated into the next model update if their priority is determined to be low. There is a freeze date associated with the data update when the plant specific failure data is collected. PRA Manual part IV chapter A [NB02] contains additional guidance on the PRA model configuration control.

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: AS-11)/Element AS; QU/Subelement AS- 9; QU-11
Treatment of the SGTR sequences involving successful steam generator isolation (SGI), successful AFW, and successful HPI seems to be non-conservative and inconsistent with the treatment of the same type of sequences in the SLOCA event tree. The SLOCA tree questions recirculation following the successful operation of AFW and HPI. In the SGTR tree such sequences are assumed to result in non-core damage and a stable end state.
Level of Significance
B. This should be addressed as soon as practically possible to obtain a more realistic risk profile.
Possible Resolution
Revise the SGTR logic to: 1. Question primary depressurization. Success of depressurization will lead to the termination of the LOCA and a successful end state. 2. Justify that following isolation of a ruptured SG, stable condition can be achieved without depressurization (i.e. sufficient water is available in the RWST to provide makeup water for a long time). This option should address how it may affect the mission time for the AFW and the HPI systems.
Plant Response or Resolution
The inventory loss from SGTRs is assumed to be much smaller than from a Small LOCA, and in fact is likely less than the inventory loss from a Small-Small LOCA (SSLOCA) event, since the break area is likely similar to a SSLOCA break size, but the break flow is spilling to SG pressure instead of Containment pressure. Since MPS3 has a very large RWST (1.2 million gallons), Sump Recirculation is not required to mitigate a SSLOCA event during the 24-hour PRA mission time. Thus, since the inventory loss is likely less in SGTR events, it is also assumed that Sump Recirculation or refill of the RWST is not required within the first 24 hours to mitigate SGTR events.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: AS-12)/Element AS/Subelement 7, 24
The event sequence pictures in the MPS3 event tree analysis notebook show, for small LOCA, an EDG branch, which the notebook explains is a way to filter out contributions from station blackout-related loss of RCP seal cooling during the quantification. However, inspection of the quantification fault tree model showed the expected logic (i.e., no EDG branch), where any SLOCA contributor was “and”ed with SLOCA mitigation logic. Another example is the absence, on the transient event trees, of PORV challenges, which are in fact modeled in the quantification fault tree. The event sequence illustrations and explanation in the event tree notebook are somewhat confusing relative to what is modeled in the actual CDF model.
Level of Significance
B (Although the event tree pictures are not used for quantification, they are presented as documentation that scenarios have been modeled appropriately. Pictures illustrating quantification techniques can be used, but an accurate representation of the actual sequence (either in event tree or fault tree top logic form) should also be presented.)
Possible Resolution
Consider explaining in either the event tree or quantification notebooks how the actual scenario is defined and the quantification model logic is set up. Also consider including, in the event tree notebook, the quantification fault tree top logic that corresponds to each event tree.
Plant Response or Resolution
The accident sequences and fault tree top logic was changed and corrected in the plethora of changes made to the MPS3 PRA Model during the M3021001 (10/2002) model update. The event trees provide a road map of the fault tree top logic and are in complete agreement. Additionally, the QU.1, QU.2, and AS.1 notebooks [NB07, NB08, and NB05] describe the accident sequences and quantification of the model.

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: AS-13)/Element AS/Subelement 7
The event tree calculation and the systems notebooks appear to include a relatively large number of conservative assumptions. While each of these viewed singly are reasonable, the peer review team is concerned that the accumulation of so many small conservative assumptions may influence the CDF estimate and may distort the relative risk significance of modeled SSCs. Achievement of the higher grades 3 and 4 in this certification process emphasize the realism of the PSA.
Level of Significance
B
Possible Resolution
To enhance confidence that the PRA can be effective in Grade 3 or 4 applications either avoid these conservative assumptions or justify why they do not, when considered cumulatively, influence the realistic estimation of CDF and LERF.
Plant Response or Resolution
A technical basis was ultimately developed for the dominant contributors to CDF; station blackout/RCP seal LOCA and small LOCA. The success criteria for the remaining scenarios were reviewed against other Westinghouse units and deemed reasonable. Incorporating the new success criteria led to a reduction in CDF as the previous criteria were determined to be overly conservative. The M3021001 (10/2002) model update [CALC04] included changes to the accident sequence analysis for LOCAs, SBO, ATWS and LOSW. Also, a number of other model changes were made to address the F&Os in the 2004 [NB26] and 2005 [NB08] model updates. For each of these model updates, there was an extensive review of the results to verify the model changes as well as to ensure the dominant sequences are reasonable.

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: AS-14)/Element AS /Subelement 7
Not all relevant systems are credited. For example, MFW, IA, condensate systems are not included in the model as a backup to the AFW system (By not including these systems the importance of the AFW system may be over-stated (may mask other risk significant contributors).
Level of Significance
B. May impact Maintenance Rule importance of the AFW system and its associated components. Could impact risk-informed AOT of the AFW components for on-line maintenance, and possibly lead to unrealistic AOT for other components.
Possible Resolution
Consider modeling the MFW system.
Plant Response or Resolution
The MFW and Condensate systems were added to the model as a backup to AFW. This was done in the March 2004 model update [NB26]. Instrument air was added to the model in the 2000 model update [CALC05].

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: AS-15)/Element AS/Subelement 10
The event sequences generally reflect dependencies among top events. However, in at least one instance, the success criteria for a top event did not appear to reflect the dependency on success of failure of the previous event: in the SGTR event tree, the AFW success criterion appears to be the same regardless of success or failure of the previous event (SG isolation function). This does not appear to be correct.
Level of Significance
A. (SGTR model correctness affects both CDF and LERF)
Possible Resolution
Review the SGTR model for consistency with plant EOPs and equipment dependencies, and ensure that the appropriate systems and success criteria are accounted for.
Plant Response or Resolution
No actions required. The peer reviewer was not familiar with the fault tree linking approach to modeling various success criteria within one system analysis.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: TH-1)/Element TH; HR/Subelement TH-4; HR-18, HR-19
With the exception of selected cases (such as the MAAP 4 evaluation of RCP seal LOCA SBO sequences, selected hand calcs for some HRA time windows, and the room heat-up calculations), nearly all of the TH analyses that support sequence modeling and system success criteria are from the original PSS. While the PSS analyses that were performed to support the Level 1 aspects may still be valid today (this needs to be confirmed) the severe accident TH analyses from the PSS were based on a pre-MAAP era level of severe accident technology (March-COCO Class 9). As noted in the NU Self Assessment report (NU-99-SAB-191) NU plans to update supporting TH analyses with MAAP 4.0. The peer review team concurs with this decision as necessary to the technical basis for the event tree and system success criteria and time windows as well as to support the Level 2 update.
Level of Significance
B
Possible Resolution
A traceable technical basis to supporting TH analyses needs to be developed, by verifying the applicability of the previous PSS analyses, performing updated analyses using MAAP or other appropriate codes or calculations, or a combination of these. The first priority in this effort should be to support the event tree and system success criteria and time windows for HRA analyses, and the second priority to support the Level 2 update.
Plant Response or Resolution
The success criteria and coping times for important phenomena were calculated using MAAP 4 [NB09]. These phenomena and associated MAAP 4 calcs for the MPS3 PRA Model are documented in the MPS3 PRA Model Notebooks SC.1 and SC.2. Also, the success criteria and coping times for the ATWS event have been completed with RELAP5.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: TH-3)/Element TH /Subelement 9 (also see F&O TH-6)
In the original PSS there is a good traceable reference path from the success criteria assumed in the event trees, fault trees, and human actions analysis to the supporting thermal hydraulics analysis (see Table 2.2.2.2-1 of the PSS). Unfortunately some of the original documents have not been retrieved or reviewed to verify continued applicability to the current design. When updating thermal hydraulic analyses using MAAP 4 or verifying applicability of the PSS analyses, such a traceable path to the current PSA logic should be established.
Level of Significance
B
Possible Resolution
Re-establish traceable path to all supporting TH analyses.
Plant Response or Resolution
This comment has been incorporated. The success criteria documentation in the AS.1, SC.1, and SC.2 model notebooks [NB05, NB06, and NB09] now provides a traceable path between the event trees, fault trees, and human actions.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: TH-5)/Element TH; AS/Subelement TH-3; AS-1
Plant-specific MAAP code runs have been performed to support timing success criteria for SBO. Calc PRA99NQA-01722-S3 (section 6.7) lists the definition of acceptable results as maximum core node temperature less than 2200°F and less than 1% clad oxidation. The calc note states that "These requirements were chosen arbitrarily since no specific guidance exists." Although the selected criterion is among those included in such sources as the draft ASME Level 1 PRA Standard (Rev 10 and 11), the documentation for the thermal hydraulic analysis/success criteria supporting the PRA should clearly define this, so that the definition of core damage, which affects all aspects of the level 1 model, is clear.
Level of Significance
B
Possible Resolution
Clearly state, for the PRA, not just for TH considerations, the criteria to be used to determine success (i.e., avoidance of core damage).
Plant Response or Resolution
See response for F&O AS-1.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: TH-6)/Element TH; HR/Subelement TH-9; HR-19 (also see F&O TH-3)
Many of the current success criteria are based on analyses performed for the original Millstone3 PSS. A review of the success criteria discussion in the PSS indicates that some of these underlying analyses exist only in Westinghouse calculation notes (1983 vintage) for which NU apparently does not have documentation, and in NU calc notes, some of which appeared to be not readily retrievable by the NU PRA group. The lack of this information makes it impossible to examine the analyses or determine their current applicability.
Level of Significance
B
Possible Resolution
Consider requesting copies of the documentation for the Westinghouse analyses supporting the original PSS, attempt to retrieve the NU analyses, review these analyses to determine their current applicability, and update the analyses if appropriate.
Plant Response or Resolution
Attempts to locate these legacy documents have not been successful. Although it is desirable to have these documents, the success criteria for the dominant sequences has been redone as noted in the response to F&O TH-1.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: TH-8)/Element TH; SY/Subelement TH-4; SY-13
In the event sequences, credit is taken for availability of AFW for 24 hours following an initiating event. The ability of AFW to provide decay heat removal for the sequence mission times (generally 24 hours) depends on the inventory available in the DWST. It was not clear to the reviewers from information in the current notebooks whether an evaluation had been made to determine that DWST volume would be sufficient to provide AFW for (and beyond) the entire mission time.
Level of Significance
B
Possible Resolution
Documentation, in the form of a calculation (or a reference to existing calcs) should be provided regarding adequacy of DWST (and CST, if appropriate) as the AFW source for modeled scenarios.
Plant Response or Resolution
The Millstone 3 PRA does not include failure of the operator action to refill the DWST upon depletion. Therefore, the impact of the depletion time change cannot be readily quantified from the PRA. However, the impact is qualitatively assessed as negligible based on the relatively long time windows available for the operator action as well as the multiple and diverse cues that signal the need for refilling the tank or aligning to the normal CST. The higher AFW flow rate for the SPU does not change the operator action time windows enough to cause a significant change in the secondary cooling function or CDF.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: SY-4)/Element SY/Subelement 8
Common cause failures and test & maintenance unavailabilities are modeled in the fault trees. However, operator errors within and across trains (e.g., equipment misposition/miscalibration errors) and false instrument signals were not observed in the models. NU has indicated that it plans to include such modeling, however.
Level of Significance
A
Possible Resolution
Implement consideration of misposition/miscalibration errors.
Plant Response or Resolution
This F&O was addressed in two parts. Misposition/Miscalibration Errors A review of each modeled system was performed to identify pre-initiator human failure events. The results of the review and changes to the model are included in the individual system model notebooks and in the HR.1 notebook [NB11]. These changes were included in the 2005 model update. False Instrument Signals An assessment of false instrument signals was completed as part of the MPS3 Fire PRA analysis (which was suspended). The Alarm Response Procedures (ARPs) were examined to identify alarms which would cause the operators to perform a detrimental action (such as shutting off a pump) without confirmation with other instruments or local checks were noted. The conclusion of each false signal was that the probability of the false signal is significantly lower (approximately 3 orders) than the failure probability of the train. Therefore, inclusion of train failure due to false instrument signals is considered to have a negligible effect on the model. Verbiage for treatment of these false alarms is added in the “Assumptions – Human Actions” section of System Notebooks SY.3.CH (SIH) [NB12], SY.3.CS (QSS and RSS) [NB13], SY.3.FW (AFW) [NB10], and SY.3.SI (RHS) [NB14].

Levels of Significance for Facts and Observations

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S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: SY-7)/Element SY/Subelement 11 (also DE-10)
The reviewers found no specific evidence in the systems analysis documentation of a check of the ability of equipment to perform in degraded environments during accidents. Although a high energy line break (HELB) analysis / Hazards Analysis have been performed, the results have apparently not been factored into the PRA in a formal manner. It is acknowledged that positive actions in this arena have been taken (such as the current modification to the Control Room entry area based on proximity of high energy lines), and that there appears to be very little, if any, HELB threat in the Control, ESF, and Aux Buildings.
Level of Significance
B
Possible Resolution
Determine, in a structured manner, if the results of the HELB analysis or other relevant evaluations of spatial interactions are relevant to equipment modeled in the PRA. Document results of this evaluation in a “Spatial Dependencies” section of the system notebook, or in a system to initiator matrix, or in both.
Plant Response or Resolution
The HELB analysis was reviewed to verify the PRA model accounts for spatial dependencies with respect to environmental conditions during a HELB. The results of the assessment are included in revision 1 of the AS.1 (Accident Sequence) notebook [NB05] in Sections 2.3.9 and 2.3.10 for Steam Line Break Inside Containment and Steam Line Break Outside Containment. Instead of documenting spatial dependencies throughout system notebooks, the spatial dependencies are documented in the model notebooks of particular spatial or environmental challenges (e.g. flooding and fire notebooks). The review concluded that the PRA model adequately accounts for the spatial dependencies associated with a HELB.

Levels of Significance for Facts and Observations

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B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
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Fact/Observation Regarding PRA Technical Elements
Observation (ID: SY-11)/Element SY/Subelement 17
The modeling for some systems has been "simplified" by selecting the most limiting success criterion and applying this whenever the system is required for mitigation, regardless of the initiating event. (An example is AFW, for decay heat removal, where flow to 2 SG's is modeled for all cases.) While this may be simpler, it may be conservative, result in less meaningful results, and is less likely to be able to support a wide range of applications.
Level of Significance
B
Possible Resolution
Ensure that the correct success criteria (and corresponding fault tree top logic) are used for each system on an initiating event-specific basis, even if this requires adding additional logic to the quantification fault tree.
Plant Response or Resolution
The current MPS3 PRA Model assumes AFW must inject to 2 of 4 steam generators (gate FWX300) [NB10]. This may be overly conservative in events in which decay heat removal is also accomplished with a break. Loss of Coolant Accident (LOCA) events in which AFW is credited are small LOCA, small-small LOCA, loss of seal cooling, and instrument tube LOCA events. If the success criteria for these events is changed to 1 of 4 steam generators, there is a negligible impact on the CDF. Therefore, no changes to the MPS3 PRA Model are required. The current MPS3 PRA Model assumes the charging system must inject to 3 of 3 intact cold legs (gate CHMODX8900), the high pressure safety injection system (HPSI) must inject to 3 of 3 intact cold legs (gate SIX101), and the low pressure safety injection system (LPSI) must inject to 2 of 3 intact cold legs (gate RHX420) [NB12 and NB14]. This may be overly conservative. If the success criteria for these systems is changed to require injection to only 1 of 3 intact cold legs, there is a negligible impact on the CDF. Therefore, no changes to the MPS3 PRA Model are required.

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: SY-13) / Element SY / Subelement 17
Loss of service water pumphouse ventilation is modeled differently for single train LOSW than for dual train LOSW. Although a reason is provided in the SW system notebook, this appears to be an overly conservative approach. Since LOSW is an important contributor to CDF, this should be re-considered. Per conversation with the PRA staff, it was noted that loss of ventilation was **not** supposed to be modeled at all. Hence there appears to be a mismatch between the model and the documentation.
Level of Significance
B
Possible Resolution
As part of the general recovery evaluation for the dominant loss of service water sequences, re-evaluate the assumptions and bases for the existing HVAC contributions to loss of SW and partial loss of SW.
Plant Response or Resolution
Based on ERC 25212-ER-04-0001 [CALC03], the temperature in the SW Cubicles would not reach the EQ temperature of 120°F for at least 7.5 days. Failure of ventilation in the SW Cubicles would not result in failure in any equipment in the MPS3 PRA Model. Thus, ventilation is not required in the SW Cubicles, and no operator actions are required for coping with the loss of ventilation. See response to F&O IE-7 for additional information on ventilation analysis. The MPS3 PRA model was revised in the 2005 model update to remove the ventilation dependencies from the SW pumps.

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: DA-1)/Element DA/Subelement 2, 4
For plant-specific data updates, the current process directs using Bayesian update only if there is a "sufficient" amount of data.
Level of Significance
B
Possible Resolution
Use Bayesian update process whenever plant specific data is available. The Bayesian process is designed to reflect the amount of evidence – a small amount of data will have a small impact on the generic distribution.
Plant Response or Resolution
The PRA engineer intended to say that Bayesian updating only makes a significant impact if there is a sufficient amount of data. Comment resolved.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID:DA-2)/Element DA/Subelement 5
For failure probabilities, valves are grouped by actuator type – motor, check, and air operated valves. There are no criteria for other data groupings of valves, for example those used in different systems.
Level of Significance
B
Possible Resolution
Consider grouping valve failure rate data by logical groupings. Groupings could be either similar types of valves (e.g., high pressure vs. low pressure MOVs) or based on data (e.g. valves with many strokes vs. few strokes). Grouping needs to balance valve differences and amount of data. As more data is available, groupings can be more specific. Document the process and/or criteria for grouping.
Plant Response or Resolution
In the 2005 model update [NB08], the reliability data was updated and the groupings of the failure data considered similar component types and the amount of data. The DA notebook series [NB15 through NB20] contains additional information on the data update.

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Fact/Observation Regarding PRA Technical Elements
Observation (ID:DA-3)/Element DA/Subelement 7
T&M unavailabilities for like components in the same system (e.g., individual Service Water pumps) are calculated separately.
Level of Significance
B
Possible Resolution
Consider lumping maintenance unavailability data together for like components in the same system. This gives a statistically better (narrower) distribution and should be appropriate unless one component is a "bad" actor.
Plant Response or Resolution
The unavailability data was updated in the 2005 model update [NB08]. This update grouped the unavailability together for like components in the same system. Additional information on the data update is included in the DA notebook series [NB15 through NB20].

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Fact/Observation Regarding PRA Technical Elements
Observation (ID:DA-4)/Element DA/Subelement 11
Discussion of the common cause coupling mechanisms for on-site AC power should be provided. (See checklist sub-element DA-11 for list).
Level of Significance
B
Possible Resolution
Specifically, discussion of why SBO diesel is independent of other EDGs should be provided, addressing these mechanisms.
Plant Response or Resolution
A common cause coupling between the emergency diesel generators and the station blackout diesel is unlikely. They have different manufacturers and designs, they are maintained and tested on separate intervals, and they are housed in different areas of the site. This has been added to the assumptions table in the SY.2 notebook [NB21].

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Fact/Observation Regarding PRA Technical Elements
Observation (ID:DA-11)/Element DA/Subelement 2, 3, 14
Overall the guidance for modeling and quantifying common cause failures covers most of the basic aspects of common cause. Guidance could be improved by providing more information on the following aspects: • when to apply common cause events to the fault trees, • how to treat CCF in initiating event models, • how to address CCF in asymmetric configurations (e.g., mix of standby and operating components), • how to address components with similar or identical parts (e.g., steam and motor driven AFW pumps), • how to address components for which there is no data, and how to incorporate plant specific data.
Level of Significance
C
Possible Resolution
Enhance guidance as suggested.
Plant Response or Resolution
The guidance for modeling and quantifying common cause events is contained in Part II of the PRA Manual chapter F section 2 [NB01]. The guidance generally follows the requirements in the ASME standard as well as guidance from NUREG/CR-5485 [REPORT2], NUREG/CR-6268 [REPORT3] and WCAP-15674 [REPORT4].

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: DA-12)/Element DA/Subelement 10, 14
The coverage of modeled common cause component groups is fairly complete but there appear to be a small number of common cause groups for which there are existing CCF data that have not been modeled. These include: CCF between motor and steam driven AFW pumps (the drivers are diverse, but the mechanical pumps may not be); batteries: transformers: reactor trip breakers. If there are components or failure modes in the CCF data that are not modeled a justification should be provided.
Level of Significance
B
Possible Resolution
Expand treatment or justify. (Also see F&O DA-11)
Plant Response or Resolution
Common cause failure basic events have been added to the model for the AFW pumps, batteries, transformers. These were added in the 2005 model update [NB08]. Notebooks SY.3.EP [NB22] and SY.3.FW [NB10] contain the documentation of these changes. Common cause failure of the reactor trip breakers was added to the model prior to the 2005 model update.

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: HR-1)/Element HR/Subelement 4 - 7 (also SY-8)
While there is guidance to consider and include Type A in the system fault trees, the process of implementing this guidance in support of the current update is still in progress and has only been implemented for a couple of human interaction modes for the RHR and SIH systems.
Level of Significance
A
Possible Resolution
Complete the evaluation of Type A actions in all of the system fault trees.
Plant Response or Resolution
A review of each modeled system was performed to identify pre-initiator human failure events. The results of the review and changes to the model are included in the individual system model notebooks and in the HR.1 notebook [NB11]. These changes were included in the 2005 model update [NB08].

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: HR-2)/Element HR/Subelement 6, 12
The HRA screening values seems to be too low to be considered as screening values. For example, the HRA value of 2.0E-4 for mis-alignment of the RHR manual return valve to the RWST (RHXVMRV43NX) seems to be very low for a screening value. Also, the screening values used do not seem to be consistent in comparison with one another. For example, the HEP value used for leaving two valves in undesired position after the test (e.g. SIBP1S1P1ANX) is assumed to be twice as much as leaving one valve in an undesired position (RHXVMRHV43NX). Such a treatment assumes total independence between the test and maintenance of the two valves configuration and in this case is conservative.
Level of Significance
B.
Possible Resolution
Either use a more conservative HRA value, compare the HRA with another HRA value of the same type which has undergone a detailed analysis or perform a detailed HRA analysis.
Plant Response or Resolution
These HEPs were revised in the 2005 model update [NB08]. The revised HEPs are documented in revision 1 of the HR.1 model notebook [NB11].

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID:HR-3)/Element HR/Subelement 9, 13, 16-18
While there is guidance to perform more detailed HRA on risk significant actions following the screening evaluation, the current PRA update has performed a detailed HRA for only one class of actions: Operators fail to switch ECCS from injection phase to recirculation phase following Large, Medium, or Small LOCA.
Level of Significance
A
Possible Resolution
Complete the detailed HRA for all risk significant HRAs, suggest that this be applied for all Type C actions whose screening values produce F-V risk importance of greater than some value no greater than $1x10^{-3}$, or other justifiable criterion. This value is selected to be somewhat lower than $5x10^{-2}$ which is often used as defining risk significant basic events in various risk ranking applications.
Plant Response or Resolution
After the peer review was completed, the entire MPS3 PRA Model was revised, including all of the HRA calculations. The quantification of the HEPs is documented in the HR series model notebooks [NB11 and NB23 through NB25].

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: HR-5)/Element HR/Subelement 14, 16-18, 20, 22
The ORE method requires simulator input. This has not yet been done, although the PRA engineer indicated that training simulator evaluations are planned for dominant actions. Formal review of risk-important operator actions by plant operations staff has not yet been undertaken.
Level of Significance
B
Possible Resolution
Obtain required input from simulator exercises, and obtain operations staff review of important operator actions.
Plant Response or Resolution
After the peer review was completed, the entire MPS3 PRA Model was revised, including all of the HRA calculations. The detailed post-initiator HRA performed following the peer review used timing input from the operations staff. The quantification of the HEPs is documented in the HR series model notebooks [NB11 and NB23 through NB25].

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: HR-6)/Element HR/Subelement 23
The reviewers noted cases where credit was taken for non-proceduralized actions.
Level of Significance
B
Possible Resolution
Provide specific justification for credit for any non-proceduralized actions, and evaluate the sensitivity of the PRA results to such credit.
Plant Response or Resolution
The only Human Error Probability (HEP) event in the model that was not proceduralized was the Operator opening the door to the AFW room on loss of ventilation. This action has since been proceduralized in station procedures OP3353.VP1B, OP3314D. See response to F&O IE-7 for additional information on ventilation analysis. The MPS3 PRA model was revised in the 2005 model update to remove Operator recoveries from the rooms that do not have a ventilation dependency. The Operator recovery for the AFW pump ventilation was updated in the 2005 model update to account for it now being proceduralized. During the peer review, this Operator recovery was not proceduralized. The new Operator recovery basic event OAPAFWVENT is documented in revision 1 of the HR.3 notebook [NB24].

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: ST-2)/Element ST/Subelement 9
The ISLOCA evaluation is a generic assessment of pipe over-pressurization pathways, and appears to have considered only a limited number of potential pathways and failure mechanisms. Since ISLOCA is typically an important LERF contributor, a more complete, updated evaluation should be prepared for use with risk-informed applications of the PRA.
Level of Significance
B
Possible Resolution
Update the ISLOCA evaluation.
Plant Response or Resolution
The ISLOCA model was updated in the 2005 mod D PRA model. The ISLOCA update was performed in accordance the guidance in NUREG/CR-5744 and NUREG/CR-5102. This is documented in revision 0 of the AS.2 PRA model notebook and revision 3 of the AS.1 PRA model notebook.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: QU-1)/Element QU/Subelement 1,3
The existing quantification calculation file provides a description of the quantification process. However, the write-up assumes that the reader is familiar with the NU-specific quantification process. A more detailed description should be provided that would allow a PRA-knowledgeable user to more easily reconstruct the analysis process. Since many of the other PRA analysis steps are described in standard procedures, consideration should be given to providing this guidance in a procedure on quantification.
Level of Significance
B
Possible Resolution
Provide additional description of the quantification process either within the calculation files, or develop a guidance procedure that details the process.
Plant Response or Resolution
The quantification process is described in the QU.1 notebook [NB07]. The QU.2 notebook [NB08] contains the results of the model update quantification.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: QU-3)/Element QU/Subelement 4
The PRA group is using the EPRI R&R Workstation suite of PRA software. This software has been validated and provides an adequate array of analysis features to support current PRA applications. However, NU does not appear to be using the latest versions of these codes, and is also using some in-house developed software that does not have as much functionality as the EPRI software. In some cases, limitations in the current versions (e.g., number of cutsets that can be generated as quantification cutoff is reduced) are limiting the ability of the PRA group to perform various sensitivity studies.
Level of Significance
B
Possible Resolution
Ensure that the PRA results and ability to be used for applications are not limited by non-current versions of the software.
Plant Response or Resolution
The latest version of the codes are used to support the model development and quantification. These versions have been improved such that the cutset limitations are no longer a problem.

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: QU-5)/Element QU/Subelement 8, 9
The first four sequences in the CDF dominant sequences list appear to be overly conservative. It is important for the dominant sequences to be as realistic as possible because of the quantitative impact on the overall PRA results, as well as for model credibility and usefulness in plant applications.
Level of Significance
C
Possible Resolution
The dominant sequences should be treated as realistically as possible. For example: 1. The common cause loss of all SW pumps should be revisited to address how to model the common cause fail to run for asymmetric conditions – i.e., the 2 running pumps vs. the 2 standby pumps. (One method is to review the INEEL common cause database for events where both operating and standby SW pumps failed to run.) 2. Another approach to the loss of SW initiator is to look at the severity of failures, based on a review of all the common cause events.
Plant Response or Resolution
The dominant sequences have changed significantly since the 1999 model that was reviewed for the peer assessment. The LOSW initiator has since been revised to incorporate differences in the running and standby SW pump CCFs. LOSW is not the dominant CDF sequences at this time. The dominant sequences have been reviewed as part of the model quantification and validation process. They have been verified to be realistic and to reflect the plant response to the initiators.

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: QU-11)/Element QU/Subelement 24
No formal convergence studies have been performed for the current PRA. The most recent revision to the model notes that a decrease of a factor of 10 in the truncation level from the previous revision resulted in 5 times as many cutsets as before.
Level of Significance
B
Possible Resolution
Perform a systematic study of calculated core damage frequency and LERF as a function of truncation level to demonstrate that the final truncation frequency is adequate to demonstrate convergence.
Plant Response or Resolution
A truncation sensitivity study is included in the QU.2 notebook [NB08].

Levels of Significance for Facts and Observations

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Fact/Observation Regarding PRA Technical Elements
Observation (ID: QU-12)/Element QU/Subelement 25
During a review of non-dominant sequences, it was noted that the TLR1 sequence of the SLBI event tree has cutsets that imply failure of HPI. However, the definition of this sequence includes the *success* of HPI. Subsequent review of the quantification details indicates that the limits of the PRA software were exceeded for this sequence. While an error message was written to a log file, this error was not evident. NU PRA staff noted that this software limitation exists in the current version of their software, but that the current software versions (not yet installed at NU) would correct this problem.
Level of Significance
B
Possible Resolution
Install the most recent software version and re-quantify the above sequence. In addition, a review should be performed of the other quantification log files to determine if other sequences are subject to the same error.
Plant Response or Resolution
After the peer review was completed, the entire MPS3 PRA Model was revised, including all of the Accident Sequence event trees and PDSs. Also, the version of the software (CAFTA) has been changed such that the cutset limitation is no longer a problem.

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: QU-13)/Element QU/Subelement 26
While the mutually exclusive rule file appears to have been constructed correctly, there is very little documentation of the rationale for each of the rules. This makes review difficult, and may result in incorrect rules begin placed in the rule file in a future update.
Level of Significance
B
Possible Resolution
More detailed description of the bases for the mutually exclusive rules should be provided in the quantification calculation. The description should, as a minimum, include a description of each class of rules that was included (e.g., “Rules 1 through 7 reflect the impossibility of being in a LOOP and non-LOOP scenario at the same time”)
Plant Response or Resolution
The mutually exclusive file is now maintained in fault tree format containing two branches. One branch models physically impossible plant configurations and the other models combinations that would violate technical specifications. The QU.1 notebook [NB07] contains a discussion of the mutually exclusive fault tree.

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: QU-14)/Element QU/Subelement 27,28,30
No uncertainty analyses have performed for the current PRA model. Uncertainty analysis is an important attribute of a complete PRA, particularly for usage of the PRA for risk-informed applications.
Level of Significance
B
Possible Resolution
Perform an uncertainty evaluation (qualitative or/or quantitative) for the current PRA, so that significant sources of uncertainty are understood and documented. Consider, for subsequent PRA updates, developing a procedure for performing uncertainty analysis, to the extent required for risk-informed applications.
Plant Response or Resolution
An uncertainty analysis was performed and documented in revision 0 of the QU.3, Model Parameter Uncertainty Analysis notebook.

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: QU-15)/Element QU /Subelement 27
In quantification of the V-sequence frequency and any other cutsets whose frequency is proportional to X^N where X is a failure rate and N is a number of independent events in the cutset having the same failure rate, the mean frequency is not equal to the Nth power of the mean failure rate. For N=2 and the case where X is lognormally distributed, $<X^2> = M^2 + \sigma^2$, where M is the mean failure rate and s^2 is the variance of the lognormal distribution. The problem is more complicated with N>2. When dealing with the V-sequence the failure rates are very low and the variance is very high such that the variance term dominates. When this is taken into account the Mean V-sequence frequency is normally at least an order of magnitude greater than the result obtained using a mean point estimate (M^2). It is not clear that this has been taken into account in the V-sequence quantification. See the Seabrook PRA for an example of correct calculation.
Level of Significance
B
Possible Resolution
Verify this issue is addressed or perform update in the next LERF update.
Plant Response or Resolution
The ISLOCA model was updated in the 2005 mod D PRA model. The ISLOCA update was performed in accordance the guidance in NUREG/CR-5744 and NUREG/CR-5102. This is documented in revision 0 of the AS.2 PRA model notebook and revision 3 of the AS.1 PRA model notebook.

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: QU-16)/Element QU/Subelement 29, 30
While the PRA software provides the capability to perform sensitivity studies, there is no procedural requirement to perform sensitivity studies on the PRA model, and only a very limited set of sensitivity studies has been performed.
Level of Significance
B Sensitivity studies are an important tool for determining the robustness of the PRA results, particularly when various PRA data inputs are believed to not have a firm basis. Sensitivity studies are also a useful tool for performing certain types of applications studies.
Possible Resolution
Proceduralize a standard set of sensitivity studies to be performed for each PRA model update, and implement that procedure.
Plant Response or Resolution
A new PRA procedure, GARD NF-AA-PRA-101-2082, was developed for model quantification. The procedure contains guidance on performing sensitivities to verify the model results.

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: QU-17)/Element QU/Subelement 31
The quantification calculation file includes a brief summary of overall results (total CDF and breakdown of CDF contribution by initiating event). However, this level of detail should be expanded to be consistent with practices used in other PRAs. This will aid in the communication of risk results and insights to plant management and staff.
Level of Significance
B
Possible Resolution
Expand the results summary to include a discussion of dominant sequences, important basic events, and important operator actions. The summary should also describe any sensitivity analyses and uncertainty performed to demonstrate the robustness of the results.
Plant Response or Resolution
After the peer review, model updates have included additional model results discussion. The Quantification Results notebook, QU.2 [NB08], contains extensive discussion on the dominant accident sequences for CDF and LERF, important Operator actions, initiators and components.

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

Fact/Observation Regarding PRA Technical Elements
Observation (ID: L2-2)/Element L2/Subelement 4-6, 8, 10
The success criteria and supporting thermal hydraulic analyses for Level 2 are from the PSS which used computer codes which were the best available at that time but are now viewed as very conservative in the modeling of early containment failure challenges. In addition, the MARCH code, used in the PSS, does not realistically model level 2 phenomena. NU plans to update the Level 2 using MAAP 4.0 which is expected to support a more realistic evaluation of the severe accident phenomena that contribute to LERF.
Level of Significance
B (for any PRA applications that may impact, or may be sensitive to, LERF)
Possible Resolution
Update L2 using contemporary realistic success criteria as planned.
Plant Response or Resolution
The level 2 analysis was updated in the 2005 mod D PRA model. The success criteria and supporting thermal hydraulic analyses were updated using MAAP 4.0. Some of the major updates include: Conditional probabilities of LERF Containment isolation analysis source term category (STC) calculations The update to the level 2 model is documented in the following PRA model notebooks: LE.1 Rev 0, LERF Analysis LE.2 Rev 0, Level 2 Analysis LE.3 Rev 0, Level 2 Supporting Analysis LE.4 Rev 0, Level 2 Thermal Hydraulic Analysis

Levels of Significance for Facts and Observations

A	Extremely important and necessary to address to ensure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process. (Contingent Item for Grade Assignment.)
B	Important and necessary to address, but may be deferred until the next PRA update (Contingent Item for Grade Assignment.)
C	Considered desirable to maintain maximum flexibility in PRA Applications and consistency in the Industry, but not likely to significantly affect results or conclusions.
D	Editorial or Minor Technical Item, left to the discretion of the host utility.
S	Superior treatment, exceeding requirements for anticipated applications and exceeding what would be found in most PRAs.

A.2.2 ASME PRA Standard Supporting Requirements that Impact Model Results

As discussed in Section A.1.2 of this attachment, an impact assessment of the supporting requirements (SRs) that were not met was performed to determine which SRs may impact the model results for the SPU. Table A.2.2-1 contains 30 SRs that were identified in this impact assessment and resolved. The remaining SRs that were assessed as not meeting category II, but not impact the results for this application are listed in Table A.2.2-2.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
AS-A5	DEFINE the accident sequence model in a manner that is consistent with the plant-specific: system design, EOPs, abnormal procedures, and plant transient response.	The accident sequences generally are modeled in a manner that is consistent with the plant-specific system design, EOPs, abnormal procedures, and plant transient response. However, model revisions are needed to response to previous recommendations: 1) determine if the hot leg recirculation function should be added to the PRA, and 2) revise the SGTR accident sequence analysis (F&O AS-11).	Perform the following model enhancements: 1) determine if the hot leg recirculation function should be added to the PRA, and 2) revise the SGTR accident sequence analysis (F&O AS-11).	Ensuring that the accident sequence analysis is complete and properly reflects plant design is an important item to be addressed in the PRA.	The model was revised and the documentation updated to the address this SR and F&O in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
DA-D3	PROVIDE a mean value of, and a statistical representation of the uncertainty intervals for, the parameter estimates of significant basic events. Acceptable systematic methods include Bayesian updating, frequent test method, or expert judgment.	Statistical parameter estimates have been provided for the generic and Bayesian-updated failure events (as documented in DOM generic MPS3 PRA Model Notebook DA.1 and MPS3 PRA Model Notebook DA.2) and common cause events (documented in DA.3). However, only mean values are documented for “special basic events” (which include alignment fractions and other events) documented in MPS3 PRA Model Notebook DA.4 and maintenance unavailabilty events (documented in MPS3 PRA Model Notebook DA.6).	Provide error factors, variances, or other statistical estimates of the uncertainty intervals for unavailability and various special basic events.	In order to properly perform the parametric uncertainty analysis for the power uprate evaluation, it will be necessary to have distribution data for all basic events.	An uncertainty analysis was performed with the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
HR-A1	For equipment modeled in the PRA, IDENTIFY, through a review of procedures and practices, those test and maintenance activities that require realignment of equipment outside its normal operational or standby status.	The Type A HRE identification employed an initial review of PRA system P&IDs to identify components potentially susceptible to Type A realignment errors, followed by a review of surveillance procedures to identify those that require realignment. The documented methodology, as summarized below, doesn't appear to discuss realignment of equipment outside its normal operational or standby status for activities other than surveillance. Also, the system notebooks summarize the Type A HRE identification findings, but the number of components listed in the notebooks appears to be too few to represent a complete inventory of manual valves for PRA systems.	Include in the Type A assessment realignment of equipment outside its normal operational or standby status for activities other than surveillance, i.e., maintenance, or document why these activities do not pose credible Type A failures.	Ensuring the technical adequacy of Type A HRA events is a key technical area in the PRA.	The model and documentation were revised to add in new type A HEPs in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
HR-F2	COMPLETE THE DEFINITION of the HFEs by specifying: 1. accident sequence specific timing of cues, and time window for successful completion 2. accident sequence specific procedural guidance (e.g., AOPs, and EOPs) 3. the availability of cues and other indications for detection and evaluation errors 4. the specific high level tasks (e.g., train level) required to achieve the goal of the response.	Most of the requirements of this SR have been satisfied. However, time windows for successful completion in some instances are not defined.	Develop time windows for successful completion of Type B and C human interactions where needed based on appropriate analyses.	Ensuring that the time windows assumed for the HEPs is a key technical issue for the PRA.	Input from Operators was obtained for response times of Operator actions. Results from thermal hydraulic runs were used for establishing the available time to perform the actions. The timing for some actions that are known to be long were not updated since the HRA calculation was not limited by the HCR/ORE method (which requires the timing). These model and documentation changes were incorporated in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
HR-G4	BASE the time available to complete actions on appropriate realistic generic thermal-hydraulic analyses, or simulation from similar plants (e.g., plant of similar design and operation). SPECIFY the point in time at which operators are expected to receive relevant indications.	Time windows available to operators have not been established using realistic generic thermal-hydraulic analyses, or simulation from similar plants for some of the HRE evaluations.	Establish the time available to complete actions based on appropriate realistic generic thermal-hydraulic analyses, or simulation from similar plants (e.g., plant of similar design and operation). Specify the point in time at which operators are expected to receive relevant indications.	Ensuring that the time windows assumed for the HEPs is a key technical issue for the PRA.	As described for HR-F2, the model and documentation were updated in the 2005 mod D model to address the timing for Operator actions.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
IE-A5	In the identification of the initiating events, INCORPORATE a. events that have occurred at conditions other than at-power operation (i.e., during low-power or shutdown conditions), and for which it is determined that the event could also occur during at-power operation. b. events resulting in a controlled shutdown that includes a scram prior to reaching low-power conditions, unless it is determined that an event is not applicable to at-power operation.	The MPS3 PRA Notebook IE.2, "Initiating Event Analysis," (Revision 1, 2005) incorporates initiating events that have occurred during full or low power operations into the IE evaluation. However, events that have occurred during shutdown conditions, or that have resulted in a controlled shutdown.	Incorporate into the plant specific initiating events analysis events that have occurred during shutdown conditions, or that have resulted in a controlled shutdown.	The inclusion of the complete spectrum of possible initiating events is a key technical requirement. Ensuring that no possible initiating events have been excluded is important for technical adequacy of the PRA.	Plant records for shutdowns and events that occurred during shutdown were reviewed. No additional initiating events were identified.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
IE-B3	GROUP initiating events only when the following can be assured: 1. events can be considered similar in terms of plant response, success criteria, timing, and the effect on the operability and performance of operators and relevant mitigating systems; or 2. events can be subsumed into a group and bounded by the worst case impacts within the "new" group.	Generally, the initiating event grouping complies with this SR based on a review of Section 2.2 and 2.5 of the MPS3 PRA Model Notebook IE.1, "Initiating Event Identification and Grouping" (Rev. 1, December 2005). However, certain groupings appear to not satisfy this SR, or are not discussed in enough detail. For example, it is not clear that the analysis avoids grouping unless the impacts are comparable to or less than those of the remaining events in that group and it is demonstrated that such grouping does not impact significant accident sequences. (Note that the NRC interpretation of "AVOID" where used in the ASME PSA Standard is considered to be "DO NOT", according to recent discussions with the NRC).	Discuss in more detail how the conclusions documented in MPS3 PRA Model Notebook IE.1 comply with this SR, or modify the analysis as appropriate.	Proper grouping of initiating events is a key technical issue. Changes in grouping could impact PRA results.	A systematic review was performed to verify the initiators included in the model. The review confirmed the existing initiators but also recommended additional investigation of some initiators to determine if they should be developed separately.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
IE-B3 (contd)	AVOID subsuming events into a group unless: 1. the impacts are comparable to or less than those of the remaining events in that group, AND 2. it is demonstrated that such grouping does not impact significant accident sequences.				The following initiators were recommended to be reviewed further: • Loss of single or multiple 120V Vital AC buses and panels • Loss of single or multiple 125V DC panels • Loss of single or multiple 4KV or 480V AC buses • Loss of Control Room HVAC • Loss of Reactor Plant HVAC System • Loss of Charging

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
IE-B3 (contd)					Further investigation and sensitivities will be performed to determine which of these initiators should be modeled separately. The results of the current model are considered acceptable in terms of evaluating the impact of the SPU since the model already includes these dependencies in the fault trees. Plus, since the risk evaluation of the SPU is focused on the change in CDF and LERF, the addition of the above initiators is not anticipated to change the conclusions.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
IE-C1	CALCULATE the initiating event frequency accounting for relevant generic and plant-specific data unless it is justified that there are adequate plant-specific data to characterize the parameter value and its uncertainty. (See also IE-C11 for requirements for rare and extremely rare events).	Based on a review of Sections 2.3 and 2.4 of MPS3 PRA Model Notebook IE.2, “Initiating Event Data Analysis,” (Rev. 2, December 2005), initiating event frequencies have been calculated using relevant generic and plant-specific data. Generic data is from: 1) NUREG/CR-5750 “Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995”, February 1999, and 2) EGG-SSRE-8875, “Generic Component Failure Data Base for Light Water and Liquid Sodium Reactor PRAs”, EG&G Idaho, 1990. Revised generic frequencies will be provided in a revision to NUREG/CR-5750 when it is published. Also, as noted by this review and the WOG PRA Review, the ISLOCA frequency is based on methods that are not current.	1. Incorporate updated generic data into the IE analysis when the revised NUREG/CR-5750 is published; 2. Re-evaluate ISLOCA frequencies using current methods.	ISLOCA upgrade should be performed in support of power uprate. As the update to NUREG/CR-5750 is not yet available, no action is needed on update of generic data.	The ISLOCA model and documentation were revised in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
IE-C9	If fault-tree modeling is used for initiating events, USE plant-specific information in the assessment and quantification of recovery actions where available, consistent with the applicable requirements in the Human Reliability Analysis section.	The MPS3 PRA models one Type B recovery action: OAPSWSTRAIN "Operator Fails To Align SW Pmp After Failure Of SW Strainer, Prior To Trip." A conservative screening HEP value is used.	If human reliability event OAPSWSTRAIN contributes significantly to the CDF results, perform a detailed HRA calculation.		This HEP was updated in the 2005 mod D model. This HEP has a very low risk significance (Fussell-Vesely is less than 5E-06).

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
IE-C12	In the ISLOCA frequency analysis, INCLUDE the following features of plant and procedures that influence the ISLOCA frequency: (a) configuration of potential pathways including numbers and types of valves and their relevant failure modes, existence and positioning of relief valves (b) provision of protective interlocks (c) relevant surveillance test procedures (d) the capability of secondary system piping (e) isolation capabilities given high flow / differential pressure conditions that might exist following breach of the secondary system	The ISLOCA frequency calculation was reviewed (W3-517-803-RE Rev. 1, “Frequency of V-Sequence at Millstone Unit 3”, May 1990). The calculation is based on methods that are not current as noted by this review and the WOG PRA Peer Review F&O IE-5. An update to the ISLOCA frequency is planned.	Re-evaluate ISLOCA frequencies based on more recent methods. Factors to consider in the re-evaluation: 1) Ensure the ISLOCA valve testing frequency accounts for the current duration between MPS3 refueling outages, if valves are tested on this cycle; and 2) Ensure calculations of time-dependent failures of standby isolation valves subject to continuous exposure before an accident utilize the equation: Pf = * Ti. For the standby isolation valves modeled by the ISLOCA frequency calculation that are subject to continuous RCS pressure exposure, the equation Pf = * Ti is appropriate.	ISLOCA is an important contributor to LERF. While the power uprate itself may not result in any changes is ISLOCA likelihood or consequences, it is important that this portion of the PRA be updated to meet current standards.	The ISLOCA model and documentation were revised in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
IE-C12 (contd)			This methodology differs from the more common calculation of time-dependent failures of standby isolation valves not subject to continuous exposure, which is computed using ½ * * Ti, the average unavailability between tests.		
LE-B1	IDENTIFY LERF contributors from the set identified in Table 4.5.9-3. INCLUDE as appropriate, unique plant issues as determined by expert judgment and/or engineering analyses.	The PSS and calculation PRA00YQA-01822S3 describe evaluations including ISLOCA, SGTR, and hydrogen detonation.	Induced SGTR was not evaluated in the MPS3 Level 2 analysis, and must be included for the LERF evaluation (note that PSS Section 4.6.2 considers a SGTR caused by a steam spike after a molten core drops, but this is not the ISGTR considered in NUREG-1570).	This item may impact the delta risk calculation because it will redistribute the LERF risk among the sequences. However, even if the impact is small, this item should be addressed in the Level 2 update.	The Level 2 model underwent an extensive revision to address these Level 2 SRs. The updated Level 2 model and documentation was included in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-B3	UTILIZE supporting engineering analyses in accordance with the applicable requirements of Table 4.5.3-2(b).	The TH and accident analysis computer codes used to support the MPS3 PSS (e.g., CORCON, COCO, MARCH) were developed 25-30 years ago, and the accident progression should be reassessed utilizing codes that have been privy to phenomenological data that have been obtained in more recent years (e.g., MAAP 4).	Update and reanalyze accident progression using a more up to date code, and factor the results into the LERF analyses. Where possible, validate code results with hand calculations, results from other codes or from experimental results.	Reanalysis of the accident sequences' progression may lead to changes in the success criteria and/or event timing.	The Level 2 model underwent an extensive revision to address these Level 2 SRs. The updated Level 2 model and documentation was included in the 2005 mod D model. The MAAP analyses were also updated.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-C1	DEVELOP accident sequences to a level of detail to account for the potential contributors identified in LE-B1 and analyzed in LE-B2. Compare the containment challenges analyzed in LE-B with the containment structural capability analyzed in LE-D and identify accident progressions that have the potential for a large early release. JUSTIFY any generic or plant-specific calculations or references used to categorize releases as non-LERF contributors based on release magnitude or timing. NUREG/CR-6595, App. A [Note (1)] provides an acceptable definition of LERF source terms.	A CET was developed in PSS Section 4 (quantified in Section 4.7) to address whether or not there was a containment bypass; if there was no bypass, then in terms of LERF, the only CET questions are whether or not a Hydrogen burn fails containment early. The CET should explicitly show the credit for ISLOCA and SGTR scrubbing that is credited in calculation PRA00YQA-01822S3; it should consider ISGTR for high-pressure sequences; a specific definition of LERF should be specified.	CET should explicitly show ISLOCA and SGTR evaluation to segregate LERF vs. non-LERF. Also, ISGTR should be considered for high-pressure sequences.	This item may impact the delta risk calculation because it will redistribute the LERF risk among the sequences. However, even if the impact is small, this item should be addressed in the Level 2 update.	The Level 2 model underwent an extensive revision to address these Level 2 SRs. The updated Level 2 model and documentation was included in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-C10	PERFORM a containment bypass analysis in a realistic manner. JUSTIFY any credit taken for scrubbing (i.e., provide an engineering basis for the decontamination factor used).	A plant-specific ISLOCA analysis was performed and presented in PSS Section 1.1.3.6.1. A conservative scrubbing factor (0.5) is credited for ISLOCAs in the RHR suction path, and none is credited for ISLOCAs in the cold leg or hot leg injection lines. For SGTR, calculation PRA00YQA-01822S3 Attachment I-D indicates that a plant-specific SGTR TH analysis has not yet been performed. Section I-6-17 identifies which SGTR sequences are considered LERF and which are not, which is based on realistic engineering judgment.	Perform plant-specific T/H calculations for SGTR. Consider additional credit for ISLOCA scrubbing. It is not known whether or not the additional analysis will alter the LERF, but because these items will dominate LERF once the CET is updated to likely substantially reduce the LERF from containment overpressurization, a more realistic analysis should be considered.	This item likely will not have much impact on the delta risk calculation. However, even if the impact is small or negligible, this item should be addressed in the ISLOCA update.	The ISLOCA and Level 2 model and documentation were revised in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-C2a	INCLUDE realistic treatment of feasible operator actions following the onset of core damage consistent with applicable procedures, e.g., EOPs/SAMGs, proceduralized actions, or Technical Support Center guidance.	The SAMGs have not been discussed in the Level 2 analysis. Generally, this is conservative in not crediting actions, but realistic evaluation may decrease the releases from some sequences. No discussion of Level 2 operator actions could be found.	Evaluate MPS3 SAMGs for possible impacts on the LERF analysis.	This item may impact the delta risk calculation because it will redistribute the LERF risk among the sequences. However, even if the impact is small, this item should be addressed in the Level 2 update.	The Level 2 model underwent an extensive revision to address these Level 2 SRs. The updated Level 2 model and documentation was included in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-C2b	REVIEW significant accident progression sequences resulting in a large early release to determine if repair of equipment can be credited. JUSTIFY credit given for repair [i.e., ensure that plant conditions do not preclude repair and actuarial data exists from which to estimate the repair failure probability (see SY-A22, DA-C14, and DA-D8)]. AC power recovery based on generic data applicable to the plant is acceptable.	The Level 2 analysis does not discuss any evaluation to determine if equipment repair could be credited in the dominant LERF sequences. It may be that no such actions can be credited, but the assessment should still be presented. Also, a discussion of the offsite power recovery data utilized should be presented.	Evaluate dominant LERF sequences for possible credit of equipment recovery.	This item may impact the delta risk calculation because it will redistribute the LERF risk among the sequences. However, even if the impact is small, this item should be addressed in the Level 2 update.	The Level 2 model underwent an extensive revision to address these Level 2 SRs. The updated Level 2 model and documentation was included in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-C6	In crediting HFEs that support the accident progression analysis, USE the applicable requirements of para. 4.5.5, as appropriate for the level of detail of the analysis.	No HFEs are developed in the Level 2 documentation. Presumably, system level HFEs for sprays, heat removal, etc., are developed in the Level 1 analysis documentation. No Level 2 operator actions were discussed in the documentation, and therefore do not require HFE evaluation. However, SAMGs should be considered for potential benefits (or damaging effects).	Consider SAMGs for possible impact on the LERF models.	This item may impact the delta risk calculation because it will redistribute the LERF risk among the sequences. However, even if the impact is small, this item should be addressed in the Level 2 update.	The Level 2 model underwent an extensive revision to address these Level 2 SRs. The updated Level 2 model and documentation was included in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-D2	When containment failure location [Note (2)] affects the event classification of the accident progression as a large early release, DEFINE failure location based on a realistic containment assessment which accounts for plant-specific features. If generic analyses are used in support of the assessment, JUSTIFY applicability to the plant being evaluated.	The containment failure location is not specified in PSS Section 4.1.1.	If the assessment shows that the containment could fail in different locations (likely with different probability distributions), then an analysis (possibly a sensitivity) should be performed to evaluate the potential effect on offsite releases.	This item likely will not have much impact on the delta risk calculation. However, even if the impact is small or negligible, this item should be addressed in the Level 2 update.	The Level 2 model underwent an extensive revision to address these Level 2 SRs. The updated Level 2 model and documentation was included in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-D4	PERFORM a realistic secondary side isolation capability analysis for the significant accident progression sequences caused by SG tube release. USE a conservative or a combination of conservative and realistic evaluation of secondary side isolation capability in similar containment designs.	Calculation PRA00YQA-01822S3, Attachment I-D indicates that no plant-specific SGTR TH analysis was performed for MPS3. However, the general modeling appears sound, and Section I-6-17 of PRA00YQA-01822S3 describes which SGTR sequences are considered LERF and which are not.	Perform a plant-specific SGTR TH analysis to calculate specific system success criteria, timing considerations and offsite release fractions.	This item likely will not have much impact on the delta risk calculation. However, even if the impact is small or negligible, this item should be addressed in the Level 2 update.	The Level 2 model underwent an extensive revision to address these Level 2 SRs. The updated Level 2 model and documentation was included in the 2005 mod D model. The MAAP analyses were also updated.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-D5	PERFORM an analysis of thermal-induced SG tube rupture that includes plant-specific procedures and design features and conditions that could impact tube failure. An acceptable approach is one that arrives at a plant-specific split fraction by selecting the SG tube conditional failure probabilities based on NUREG-1570 [Note (3)] or similar evaluation for induced SG failure of similarly designed SGs and loop piping.	ISGTR was not considered in the MPS3 Level 2 analysis.	Include ISGTR as a potential containment bypass. The ASME PRA Standard suggests the use of NUREG-1570 to assess ISGTR conditional probabilities.	This item may impact the delta risk calculation because it will redistribute the LERF risk among the sequences. However, even if the impact is small, this item should be addressed in the Level 2 update.	In the updated Level 2 analysis, ISGTR was included in the model and documentation of the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-D5 (contd)	SELECT failure probabilities based on a. RCS and SG post-accident conditions sufficient to describe the important risk outcomes b. secondary side conditions including plant-specific treatment of MSSV and ADV failures				

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-D5 (contd)	JUSTIFY key assumptions and election of key inputs. An acceptable justification can be obtained by the extrapolation of the information in NUREG-1570 to obtain plant-specific models, use of reasonably bounding assumptions, or performance of sensitivity studies indicating low sensitivity to changes in the range in question.				

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
LE-E3	INCLUDE as LERF contributors potential large early release (LER) sequences identified from the results of the accident progression analysis of LE-C except those LER sequences justified as non-LERF contributors in LE-C1.	The potential contributors to LERF are presented in PRA calculation file PRA00YQA-01822S3, Section I-6-17, which identifies the PSS release categories considered large, early releases. Section I-6-17 also describes the ISLOCA scrubbing and the SGTR sequences not considered LERF. The “large, early” definition is applied to release categories M5 and M6 because of limitations in the TH codes used in the PSS.	The development of PRA00YQA-01822S3 is necessarily conservative because the only information available was the PSS, which was based on codes limited to the time frame in which the PSS was developed. As a result, the dominant contributors to LERF are LOCAs with no Quench Sprays (per PRA00YQA-01822S3 Volume IV, these comprise 58% of the MPS3 LERF). In a large, dry containment, such sequences generally should not cause a large, early release, so the Level 2 model should be updated to possibly remove these sequences from the LERF category.	This item may impact the delta risk calculation because it will redistribute the LERF risk among the sequences. However, even if the impact is small, this item should be addressed in the Level 2 update.	The Level 2 model underwent an extensive revision to address these Level 2 SRs. The updated Level 2 model and documentation was included in the 2005 mod D model.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
QU-A2b	ESTIMATE the mean CDF from internal events, accounting for the “state-of-knowledge” correlation between event probabilities when significant [Note (1)].	The intent of this SR is to provide a true mean value for the CDF. In order to calculate the true MEAN value it is necessary to perform an uncertainty calculation, including correlation of data from similar sources.	Resolve the open task (QU-14) to perform an uncertainty analysis on the final quantification results, accounting for the “state-of-knowledge” correlation between BE probabilities.	Lack of an uncertainty analysis is a model weakness in a technical area of high interest.	An uncertainty analysis was performed using the 2005 mod D model and documented in the Model Parameter Uncertainty Analysis notebook.
QU-E1	IDENTIFY key sources of model uncertainty.	Key sources of model uncertainty have not been identified for the MPS3 model.		The consideration of key sources of uncertainty is a specific technical requirement of the Standard. Not performing such a study could complicate the response to potential questions in this area as part of the power uprate submittal.	An assessment of the key sources of uncertainty was performed using the 2005 mod D model and documented in the Model Parameter Uncertainty Analysis notebook.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
QU-E2	IDENTIFY key assumptions made in the development of the PRA model.	Although the system notebooks (specifically Table 1 in Volume SY.2) and other documentation volumes identify numerous assumptions made during model development, the key assumptions made have not been identified for the MPS3 model.		The identification of key assumptions is a specific technical requirement of the Standard. Not performing such a study could complicate the response to potential questions in this area as part of the power uprate submittal.	An assessment of the key sources of uncertainty was performed using the 2005 mod D model and documented in the Model Parameter Uncertainty Analysis notebook.
QU-E3	ESTIMATE the uncertainty interval of the overall CDF results. ESTIMATE the uncertainty intervals associated with parameter uncertainties (DA-D3, HR-D6, HR-G9, IE-C13), taking into account the "state-of-knowledge" correlation	No parametric uncertainty analysis has been performed for the MPS3 PRA.	Resolve the open task (QU-14) to perform an uncertainty analysis on the final quantification results, accounting for the "state-of-knowledge" correlation between BE probabilities.	Lack of an uncertainty analysis is a model weakness in a technical area of high interest.	An uncertainty analysis was performed using the 2005 mod D model and documented in the Model Parameter Uncertainty Analysis notebook.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
QU-E4	EVALUATE the sensitivity of the results to key model uncertainties and key assumptions using sensitivity analyses [Note (1)].	The current version (R2) of the MPS3 PRA Model Notebook QU.2 Quantification Model Results Notebook includes no sensitivity analyses, the previous version (R1) describes 4 "general" sensitivity cases that were performed (setting specific basic events in the cutset file to 1 or 0, setting basic events to their previous values, tracing cutsets through the fault tree using browser, solving the model with specific dependencies removed). The purpose of these sensitivities was to verify the model changes were correct. However, these cases and their results are not well documented. In addition, an alternating train sensitivity case is suggested for the EOOS model, but evidently was not performed.	Resolve open item (QU-16) to prepare a standard set of sensitivity studies. Ensure that the sensitivity cases developed are designed to determine the impact of key model uncertainties and associated key assumptions.	Lack of comprehensive sensitivity analysis is a model weakness in a technical area of high interest.	An assessment of the key sources of uncertainty was performed using the 2005 mod D model and documented in the Model Parameter Uncertainty Analysis notebook.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
QU-E4 (contd)		Finally, the sensitivity cases described have no basis or relation to the key model uncertainties and key assumptions.			

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
QU-F2	DOCUMENT the model integration process, including any recovery analysis, and the results of the quantification including uncertainty and sensitivity analyses. For example, documentation typically includes (a) records of the process/results when adding nonrecovery terms as part of the final quantification (b) records of the cutset review process (c) a general description of the quantification process including accounting for systems successes, the truncation values used, how recovery and post-initiator HFEs are applied	The MPS3 PRA Model Notebook QU.1 and QU.2 quantification notebooks currently document the following elements, but do not document several of the other elements suggested in this SR. (c) a general description of the quantification process including accounting for systems successes, the truncation values used, how recovery and post-initiator HFEs are applied (d) the process and results for establishing the truncation screening values for final quantification demonstrating that convergence towards a stable result was achieved (e) the total plant CDF and contributions from the different initiating events and accident classes (f) the accident sequences	Resolve open item (QU-7) to eliminate asymmetries in the AFW FT for SGTR and SLBI, and consider eliminating asymmetry from assuming LOCA occurs in loop 1.	The elimination of asymmetries in the AFW FT for SGTR and SLBI, and in the LOCA initiating event is a task previously identified for inclusion in the MPS3 model upgrade.	The model and documentation have been revised in the 2005 mod D model to address these asymmetries.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
QU-F2 (contd)	(d) the process and results for establishing the truncation screening values for final quantification demonstrating that convergence towards a stable result was achieved (e) the total plant CDF and contributions from the different initiating events and accident classes (f) the accident sequences and their contributing cutsets (g) equipment or human actions that are the key factors in causing the accidents to be nondominant (h) the results of all sensitivity studies (i) the uncertainty distribution for the total CDF (j) importance measure results	(j) importance measure results			

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
QU-F2 (contd)	(k) a list of mutually exclusive events eliminated from the resulting cutsets and their bases for Elimination (l) asymmetries in quantitative modeling to provide application users the necessary understanding regarding why such asymmetries are present in the model (m) the process used to illustrate the computer code(s) used to perform the quantification will yield correct results process				

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
SC-A6	CONFIRM that the bases for the success criteria are consistent with the features, procedures, and operating philosophy of the plant.	MPS3 PRA Model Notebook SC.1 notes that success criteria have been developed in accordance with plant design. MPS3 PRA Model Notebook SC.2 also references various operating procedures. The success criteria that are selected appear to be appropriate (as compared to those used in other Westinghouse PWRs). However, there are two specific success criteria that are used in the PRA that seem inconsistent with plant design and other Westinghouse PRAs. First, the large LOCA accident sequence does not consider the need for hot leg recirculation and no basis is provided for excluding hot leg recirculation from the model.	The PRA model for large LOCA should consider the impacts of failure of hot leg recirculation, unless it can be demonstrated to not be required. Consideration of the possibility of a mechanical scram failure during a total loss of DC (presumably this would lead directly to core damage) should also be given.	Ensuring that the accident sequence and success criteria analyses are complete and properly reflects plant design is an important item to be addressed in the PRA.	The 2005 mod D model and documentation were revised to include Hot Leg Recirculation in the large LOCA event tree. The mechanical scram failure during a loss of DC event was not included due to the very low likelihood of this combination. The RCP seal LOCA documentation is complete.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
SC-A6 (contd)		Second, the Total Loss of DC event does not consider the possibility that the reactor does not scram due to mechanical faults (as is assumed for all other initiating events). The assumption that a scram will occur is non-conservative. However, the overall probability of this ATWS scenario is most likely very low. Also, it is not clear if the RCP seal LOCA documentation has been fully updated to reflect the most recent information about the use of Framatome seals (i.e., there is a separate document discussing this which does not appear to be fully factored into the notebooks).			

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
SY-A5	INCLUDE the effects of both normal and alternate system alignments, to the extent needed for CDF and LERF determination.	Many of the system models include multiple top events, some of which represent alternate system functions or alignments. For example, the model for the charging/high head SI system includes the alignments for RCP seal injection, RCS injection flow, RCS sump recirculation flow, emergency boration, and natural circulation. Other systems such as component cooling and service water consider normal and alternate cross-tie alignments, and the system notebooks identify which of those alignments are modeled and which are not.	Complete the model upgrade task to incorporate hot leg recirculation in the PRA model	The incorporation of hot leg recirculation is a task previously identified for inclusion in the MPS3 model upgrade.	The 2005 mod D model and documentation were revised to include Hot Leg Recirculation in the large LOCA event tree.

Table A.2.2-1 Supporting Requirements Determined to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Impact Comments	Resolution
SY-B8	IDENTIFY spatial and environmental hazards that may impact multiple systems or redundant components in the same system, and ACCOUNT for them in the system fault tree or the accident sequence evaluation. Example: Use results of plant walkdowns as a source of information regarding spatial/environmental hazards, for resolution of spatial/ environmental issues, or evaluation of the impacts of such hazards.	The current system notebooks reference separate fire, internal flood, and seismic analysis notebooks for discussion of spatial and environmental hazards. The current system notebooks do not include any discussion of plant walkdowns. Only the internal flooding notebooks are available for review (which is discussed with those SRs for the IF element), however the IF notebooks and model have not yet been approved and incorporated in the model of record. The current notebooks also refer to a previous version of MPS3 PRA documentation for historical purposes. However, this historical version of the PRA also does not include discussion of spatial and environmental hazards nor walkdowns performed.	Resolve open item (SY-7, DE-1, DE-2, DE-3) to perform spatial dependency analysis within each systems analysis, and approve then incorporate the updated internal flooding analysis into the model of record.	The incorporation of internal flooding into the official model is a task previously identified for inclusion in the MPS3 model upgrade.	The internal flooding analysis was completed and issued in the 2005 mod C model. The spatial dependencies are documented in the model notebooks of particular spatial or environmental challenges (e.g., flooding and fire notebooks). The review concluded that the PRA model adequately accounts for the spatial dependencies associated with a HELB and internal flooding.

Table A.2.2-2 contains the ASME supporting requirements (SRs) in which the Millstone 3 model does not meet category II but, were assessed to not have an impact on the power uprate application.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IE-A3	REVIEW the plant-specific initiating event experience of all initiators to ensure that the list of challenges accounts for plant experience. See also IE-A7	The MPS3 PRA Model Notebook IE.2, “Initiating Event Analysis,” (Revision 1, 2005) reviewed all plant shutdown events documented in Licensee Event Reports during the life of the plant. The review identified a Loss of Instrument Air for inclusion in the PRA. However, as noted in the comments for IE-A5 and IE-7, the following events don’t appear to be included in the evaluation: 1) those that have occurred during shutdown conditions, or have resulted in a controlled shutdown, or 2) initiating event precursors.	See recommendations for IE-A5 and IE-A7.	

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IE-A4	PERFORM a systematic evaluation of each system, including support systems, to assess the possibility of an initiating event occurring due to a failure of the system. USE a structured approach (such as a system-by-system review of initiating event potential, or an FMEA [failure modes and effects analysis] or other systematic process) to assess and document the possibility of an initiating event resulting from individual systems or train failures.	A systematic evaluation of each system, including support systems, to assess the possibility of an initiating event occurring due to a failure of the system was performed and clearly documented in Section 2.2 of the MPS3 PRA Model Notebook IE.1, “Initiating Event Identification and Grouping,” (Rev. 1, December 2005). An inventory of plant systems is reviewed, and conclusions appear to be appropriate. No evaluation of switchgear room HVAC currently appears to be performed (the WOG PRA Peer Review also provided this observation in F&O IE-7).		Ensure that discussions of plant systems reviewed is complete. For example, include comments about consideration of losses of switchgear room HVAC and provide the rationale for excluding switchgear room HVAC as an initiating event.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IE-A4a	When performing the systematic evaluation required in IE-A4, INCLUDE initiating events resulting from multiple failures, if the equipment failures result from a common cause, and from routine system alignments.	Section 2.2 of the MPS3 PRA Model Notebook, Initiating Event Identification and Grouping (Volume IE.1, Rev. 1, December 2005) documents consideration of initiating events resulting from multiple failures, if the equipment failures result from a common cause. However, no discussion appears to be provided of the influences from routine system alignments.		Include a discussion in the MPS3 PRA Model Notebook IE.1 initiating events identification notebook of how the PRA model accounts the influences of system alignments on initiating event frequencies (particularly initiating event frequencies modeled using fault tree analysis).
IE-A6	INTERVIEW plant personnel (e.g., operations, maintenance, engineering, safety analysis) to determine if potential initiating events have been overlooked.	No documentation of plant personnel interviews to determine if potential initiating events have been overlooked was found in the PRA notebooks.		Interview plant personnel to determine if potential MPS3 initiating events have been overlooked.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IE-A7	REVIEW plant-specific operating experience for initiating event precursors, for the purpose of identifying additional initiating events. For example, plant specific experience with intake structure clogging might indicate that loss of intake structures should be identified as a potential initiating event.	No documentation of the review of plant-specific operating experience for initiating event precursors was found in the PRA notebooks.		Include in the IE evaluation a review of plant-specific operating experience for initiating event precursors.
IE-C3	Calculate initiating event frequencies on a reactor-year basis. [See Note 3] Include in the initiating event analysis the plant availability, such that the frequencies are weighted by the fraction of time the plant is at-power.	The MPS3 PRA Model Notebook IE.2 notebook does not appear to calculate initiating event frequencies on a reactor-year basis.	Calculate and document initiating event frequencies on a reactor-year basis.	Document the basis for the availability factor used to convert initiating event frequencies to events per reactor year.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IE-C4	USE as screening criteria no higher than the following characteristics (or more stringent characteristics as devised by the analyst) to eliminate initiating events or groups from further evaluation: (a) the frequency of the event is less than 1E-7 per reactor-year (/yr) and the event does not involve either an ISLOCA, containment bypass, or reactor pressure vessel rupture (b) the frequency of the event is less than 1E-6/yr and core damage could not occur unless at least two trains of mitigating systems are failed independent of the initiator, or	Quantitative screening does not appear to be performed, based on a review of the PRA IE Notebooks.		If quantitative screening is elected to be performed (in response to the recommendations for IE-B3, for example), using the following screening criteria: (a) the frequency of the event is less than 1E-7 per reactor-year and the event does not involve either an ISLOCA, containment bypass, or reactor pressure vessel rupture (b) the frequency of the event is less than 1E-6/yr and core damage could not occur unless at least two trains of mitigating systems are failed independent of the initiator, or

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IE-C4 (contd)	(c) the resulting reactor shutdown is not an immediate occurrence. That is, the event does not require the plant to go to shutdown conditions until sufficient time has expired during which the initiating event conditions, with a high degree of certainty (based on supporting calculations), are detected and corrected before normal plant operation is curtailed (either administratively or automatically). If either criterion (a) or (b) above is used, then CONFIRM that the value specified in the criterion meets the applicable requirements in the Data Analysis section (para. 4.5.6) and the Level 1 Quantification section (para. 4.5.8).			(c) the resulting reactor shutdown is not an immediate occurrence. That is, the event does not require the plant to go to shutdown conditions until sufficient time has expired during which the initiating event conditions, with a high degree of certainty (based on supporting calculations), are detected and corrected before normal plant operation is curtailed (either administratively or automatically). If either criterion (a) or (b) above is used, then CONFIRM that the value specified in the criterion meets the applicable requirements in the Data Analysis section (para. 4.5.6) and the Level 1 Quantification section (para. 4.5.8).

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IE-C7	If fault tree modeling is used for initiating events, QUANTIFY the initiating event frequency (as opposed to the probability of an initiating event over a specific time frame, which is the usual fault tree quantification model described in the Systems Analysis section, para. 4.5.4.). MODIFY as necessary the fault tree computational methods that are used so that the top event quantification produces a failure frequency rather than a top event probability as normally computed. USE the applicable requirements in the Data Analysis section, para. 4.5.6, for the data used in the fault-tree quantification.	Initiating events that rely upon fault tree modeling correctly produce failure frequencies rather than top event probabilities. SR IE-C3 requires the failure frequencies to be computed in terms of reactor years.	Modify the initiating event fault trees to compute initiating event frequencies in terms of reactor years.	

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IE-C10	COMPARE results and EXPLAIN differences in the initiating event analysis with generic data sources to provide a reasonableness check of the results.	Based on documentation in Section 2.5 of MPS3 PRA Model Notebook, Initiating Event Data Analysis (Volume IE.2, Rev. 2, December 2005), two the initiating event frequencies that were Bayesian updated from generic values (that is, GPT, LMFW) remain relatively consistent with the generic estimates from NUREG/CR-5750 "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995", February 1999. A Bayesian update was also performed for expansion joint rupture frequencies, but no reasonableness check was made. Also, a review of the initiating event frequency point estimates used in other four-loop Westinghouse plants was satisfactorily performed and documented in IE.2. The results of the comparison show that the MPS3 initiating event frequencies are comparable to those of other similar plants in the industry.	Perform a reasonableness check of the expansion joint rupture frequencies modeled in the PRA (Section 2.4.6 of MPS3 PRA Model Notebook, Initiating Event Data Analysis (Volume IE.2, Rev. 2, December 2005)).	

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
AS-A1	USE a method for accident sequence analysis that (a) explicitly models the appropriate combinations of system responses and operator actions that affect the key safety functions for each modeled initiating event; (b) includes a graphical representation of the accident sequences in an “event tree structure” or equivalent such that the accident sequence progression is displayed; and (c) provides a framework to support sequence quantification.	The MPS3 PRA employs the small event tree/large fault tree method to model combinations of system responses and operator actions. The PRA is quantified using a “top logic” fault tree that solves fault tree top gates to solve accident sequences. It is noted that for PRA update M304A, changes to the accident sequence modeling were made only to the top logic model but apparently were not made to the event tree files, since it was not essential to the model update process (Attachment 3 of MPS3 PRA Model Notebook Volume AS.1, “Accident Sequence Analysis,” Rev. 2, February 2006). Event tree models provide a graphical representation of accident sequences that is often useful for full comprehension of the PRA.		Remove the statement in Attachment 3 of AS.1 that changes made for the M304A PRA update were made only to the top logic model and not the event tree model.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
AS-B3	For each accident sequence, IDENTIFY the phenomenological conditions created by the accident progression. Phenomenological impacts include generation of harsh environments affecting temperature, pressure, debris, water levels, humidity, etc. that could impact the success of the system or function under consideration [e.g., loss of pump net positive suction head (NPSH), clogging of flow paths]. INCLUDE the impact of the accident progression phenomena, either in the accident sequence models or in the system models.	MPS3 PRA Model Notebook AS.1 addresses some of the phenomenological conditions created by accident progressions.		Add more specific discussions of phenomenological conditions expected for each initiating event.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
AS-B6	MODEL time-phased dependencies (i.e., those that change as the accident progresses, due to such factors as depletion of resources, recovery of resources, and changes in loads) in the accident sequences. Examples are: (a) For SBO/LOOP sequences, key time-phased events, such as: (1) AC power recovery (2) DC battery adequacy (time-dependent discharge) (3) Environmental conditions (e.g., room cooling) for operating equipment and the control room (b) For ATWS/failure to scram events (for BWRs), key time-dependent actions such as: (1) SLCS initiation (2) RPV level control (3) ADS inhibit (c) Other events that may be subject to explicit time-dependent characterization include: (1) CRD as an adequate RPV injection source (2) Long term make-up to RWST	Time-phased dependencies don't appear to be discussed in sufficient detail to provide an understanding of how such dependencies impact the progression and modeling of accident sequences.		Document in more detail MPS3 time-phased dependencies, or provide summaries and cross-references in the MPS3 PRA Model Notebook AS.1. For example, for SBO/LOOP sequences, key time-phased events include: (1) AC power recovery (2) DC battery adequacy (time-dependent discharge) (3) Environmental conditions (e.g., room cooling) for operating equipment and the control room

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SC-A1	USE the definition of core damage provided in Section 2 of this Standard. If core damage has been defined differently than in Section 2 (a) IDENTIFY any substantial differences from the Section 2 definition (b) PROVIDE the bases for the selected definition	The definition of “core damage” defined in the Standard appears to be the criterion used in the MPS3 PRA (based on the physical parameters used and the success criteria described in MPS3 PRA Model Notebook SC.1). However, the actual definition used is not specifically stated anywhere. The MPS3 PRA Model Notebook SC.1 indicates that the core damage definition is presented in the PRA Manual. However, the referenced section of the manual (Part C for success criteria) has not yet been issued as an official document. In lieu of referring to the PRA Manual, the documentation could be revised to include the definition or to reference the definition used in the Standard. This is a minor documentation issue.		If the PRA Manual, Part C is not issued I the near-term (or does not include the definition of core damage, add either an explicit definition of “core damage” to the MPS3 PRA Model Notebook SC.1, or include a reference to the definition provided in the Standard.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SC-A4	SPECIFY success criteria for each of the key safety functions identified per SR AS-A2 for each modeled initiating event [Note (2)].	MPS3 PRA Model Notebook SC.1 describes the specific safety function success criteria for each initiating event. However, the timing available to provide each safety function is often not indicated. In general, the success criteria for which plant-specific analyses have been performed often do contain specific timing items. But those obtained from generic studies, the previous Probabilistic Safety Study and FSAR often do not contain such details		The discussion of time windows available to perform each safety function should be included for each function for each initiating event. In cases where plant-specific timing is not available from the reference information, a realistic by conservative assumption should be made (and stated as such) for the functions.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SC-A4a	IDENTIFY mitigating systems that are shared between units, and the manner in which the sharing is performed should both units experience a common initiating event (e.g., LOOP).	In general, MPS3 does not share systems with MPS2. However, the one exception is the SBO Diesel Generator. The fact that this diesel is a shared system and could only be used by one unit in a blackout event is not noted in the MPS3 PRA Model Notebook SC.1. As a related item, SBO is not discussed in SC.1 in terms of its unique functional success criteria (i.e., it is lumped into the transient discussion). MPS3 PRA Model Notebook SC.2 includes specific discussion of the SBO event and specific timing issues. However, the shared status of the SBO diesel is not discussed.		The MPS3 PRA Model Notebooks SC.1 or SC.2 should discuss the unique shared-unit aspects of the SBO diesel. SC.1 should also be updated to included to specifically discuss the SBO success criteria, consistent with the discussions provided for other initiating event.

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SC-A5	SPECIFY an appropriate mission time for the modeled accident sequences. For sequences in which stable plant conditions have been achieved, USE a minimum mission time of 24 hr. Mission times for individual SSCs that function during the accident sequence may be less than 24 hr, as long as an appropriate set of SSCs and operator actions are modeled to support the full sequence mission time. For example, if following a LOCA, low pressure injection is available for 1 hr, after which recirculation is required, the mission time for LPSI may be 1 hr and the mission time for recirculation may be 23 hr.	A 24-hour mission time is used for each system if a stable state is achieved, but this is not stated in MPS3 PRA Model Notebook SC.1. The Notebook does not identify any specific cases in which alternate mission times are used (i.e., the 24-hour time appears to be used for all initiating events). MPS3 PRA Model Notebook SC.1 notes that the PRA Manual, Part C describes the mission time selection process. However, Part C of the PRA Manual has not yet been issued.		If the PRA Manual, Part C is not issued in the near-term or does not include a discussion of mission time, add a mission time discussion to the MPS3 PRA Model Notebook SC.1.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SC-B1	USE appropriate realistic generic analyses/evaluations that are applicable to the plant for thermal/hydraulic, structural, and other supporting engineering bases in support of success criteria requiring detailed computer modeling. Realistic models or analyses may be supplemented with plant-specific/generic FSAR or other conservative analysis applicable to the plant, but only if such supplemental analyses do not affect the determination of which combinations of systems and trains of systems are required to respond to an initiating event.	The success criteria are selected based on a combination of plant-specific evaluations (using MAAP, RELAP and other codes), owners group evaluations, and FSAR criteria. Where FSAR criteria are used, this fact is documented, and it does not appear that the usage of these conservative criteria have significantly affected the overall success criteria (as compared to those used in other plants). However, some of the success criteria for certain events (such as large LOCA) are based on the initial success criteria used in the 1983 Probabilistic Safety Study, for which supporting reference data may not be available. The success criteria that are being used appear to be consistent with those used at other similar plants. However, the traceability of the basis for these criteria may be difficult to obtain.		The success criteria documentation should attempt to use more modern references for those success criteria that are currently derived from the PSS. This is a documentation/traceability issue only.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SC-B5	CHECK the reasonableness and acceptability of the results of the thermal/hydraulic, structural, or other supporting engineering bases used to support the success criteria. Examples of methods to achieve this include: (a) comparison with results of the same analyses performed for similar plants, accounting for differences in unique plant features (b) comparison with results of similar analyses performed with other plant-specific codes (c) check by other means appropriate to the particular analysis	In several instances in MPS3 PRA Model Notebook SC.2, comparisons are provided for specific success criteria used at other plants. However, neither MPS3 PRA Model Notebook SC.1 or SC.2 contains an overall comparison of the success criteria used for MPS3 to other plants or comparisons of results from other computer codes.		Using data from sources such as the WOG PRA Comparison Database, include a specific comparison of the MPS3 criteria to other similar plants, including a discussion of any differences in criteria used.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SC-C1	DOCUMENT the success criteria in a manner that facilitates PRA applications, upgrades, and peer review.	The overall documentation of success criteria presented in MPS3 PRA Model Notebooks SC.1 and SC.2 is thorough and easy to use to identify the criteria used and the bases for specific criteria. However, the lack of timing information for each success criteria could impede future reviews of the PRA and future applications.		Specific time window information should be provided consistently for each safety function for each initiating event

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SC-C2	DOCUMENT the processes used to develop overall PRA success criteria and the supporting engineering bases, including the inputs, methods, and results. For example, this documentation typically includes: 1. the definition of core damage used in the PRA including the bases for any selected parameter value used in the definition (e.g., peak cladding temperature or reactor vessel level) 2. calculations (generic and plant-specific) or other references used to establish success criteria, and identification of cases for which they are used 3. identification of computer codes or other methods used to establish plant-specific success criteria	In general, the documentation presented in MPS3 PRA Model Notebooks SC.1 and SC.2 meet many of the specific requirements listed in this SR. However, certain documentation could be improved, including: a description of the limitations of the computer codes used and the resulting analyses (item d), and the basis for time available for human actions (item g).		Ensure that the SC notebooks address all of the specific documentation items noted in this SR

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SC-C2 (contd)	4. a description of the limitations (e.g., potential conservatisms or limitations that could challenge the applicability of computer models in certain cases) of the calculations or codes 5. the uses of expert judgment within the PRA, and rationale for such uses 6. (f) a summary of success criteria for the available mitigating systems and human actions for each accident initiating group modeled in the PRA 7. the basis for establishing the time available for human actions 8. descriptions of processes used to define success criteria for grouped initiating events or accident sequences			

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SC-C3	DOCUMENT the key assumptions and key sources of uncertainty associated with the development of success criteria.	The MPS3 PRA Model Notebooks SC.1 and SC.2 list the specific assumptions used in the course of developing the success criteria. However, the notebooks do not discuss which of these are “key assumptions” as defined by the Standard. Similarly there is no discussion of the “key uncertainties.” Note that some of the identification process can be performed during the model quantification phase (since the results of sensitivity studies is often used to determine which assumptions are “key”).		MPS3 PRA Model Notebook SC.1 should be updated to include a discussion of key assumptions and uncertainties. If this assessment is performed elsewhere (e.g., during quantification), then a reference should be provided in this notebook to the location of the assessment to aid future reviews.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A2	COLLECT pertinent information to ensure that the systems analysis appropriately reflects the as-built and as-operated systems. Examples of such information include system P&IDs, one-line diagrams, instrumentation and control drawings, spatial layout drawings, system operating procedures, abnormal operating procedures, emergency procedures, success criteria calculations, the final or updated SAR, Technical Specifications, training information, system descriptions and related design documents, actual system operating experience, and interviews with system engineers and operators.	The current system notebooks typically reference only system P&IDs, and in some cases a few operating procedures or engineering analyses. The current notebooks also refer to a previous version of MPS3 PRA documentation for historical purposes. This historical version of the PRA includes reference to the information collected including one-lines, I&C drawings, layouts, surveillance procedures, OPs, ARPs, Tech Specs, etc., but there is no discussion of the information obtained from these sources in the current documentation. The resolution to F&O AS-8 describes how current versions of the system information sources have been reviewed in order to verify the system models reflect the as-built, as-operated systems.		If the previous version of the MPS3 PRA notebooks is to be used for information-only and is not intended to be the primary documentation for the current model, it is suggested a separate table of information sources be developed for the system models. This table could be similar to that developed for the system analysis dependencies, assumptions and success criteria (i.e., a single table for all systems). The table should list all pertinent information sources, and could include the version on which the analysis is based and the current version (if different). Note that the current dependency matrix Table 1 in Volume SY.1 does list mechanical and electrical drawing numbers.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A3	REVIEW plant information sources to define or establish: • system components and boundaries • dependencies on other systems • instrumentation and control requirements • testing and maintenance requirements and practices • operating limitations such as those imposed by Technical Specifications • component operability and design limits • procedures for the operation of the system during normal and accident conditions • system configuration during normal and accident conditions	The current system notebooks describe the system components and boundaries, dependencies on other systems (including I&C requirements such as actuation circuits, interlocks and control power), and system configuration during normal and accident conditions. In some cases there may be assumptions based on tech spec limitations or testing and maintenance (TM) practices. The current notebooks also refer to a previous version of MPS3 PRA documentation for historical purposes. This historical version of the PRA included discussion of TM requirements and practices, but there is no discussion of these items in the current documentation and neither notebook describes component operability and design limits, normal and accident operating procedures, etc.		If the previous version of the MPS3 PRA is to be used for information-only and is not intended to be the primary documentation for the current model, it is suggested a separate table of system information be developed for the various system models. This table could be similar to that developed for the system analysis dependencies, assumptions and success criteria (i.e., a single table for all systems), or the information could be included within additional categories for the existing assumptions table (Table 1 of Volume SY.2). The table should establish TM requirements, component operability and design limits, applicable operating procedures, and any other items from this SR not discussed in the current notebooks.

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	**Category II**	**Assessment Comments**	**Model Enhancement**	**Documentation Enhancement**
SY-A4	PERFORM plant walkdowns and interviews with system engineers and plant operators to confirm that the systems analysis correctly reflects the as-built, as-operated plant.	The current system notebooks describe the systems analysis but do not include any discussion of plant walkdowns or interviews with system engineers or operators. The current notebooks also refer to a previous version of MPS3 PRA documentation for historical purposes. However, this historical version of the PRA also does not include discussion of walkdowns performed and interviews conducted.		It is suggested a separate reference be provided (e.g., walkdown checklists or interview notes) for the items required by this SR.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A6	In defining the system model boundary (see SY-A3), INCLUDE within the boundary the components required for system operation, and the components providing the interfaces with support systems required for actuation and operation of the system components.	The system notebooks include simplified schematics that generally specify the system boundaries (although not all components shown in the schematics are modeled, just those required to meet the specific success criteria), and a table within each system notebooks identifies the specific components contained in the fault tree. In addition, the system dependency matrix (Table 1 in volume SY.1) identifies the components that provide interfaces with the support systems (e.g., breakers for motive power, circuits for control power, etc.), although it is not clearly specified which interface components are included within a particular system boundary.		Consider developing a companion table to the system dependency matrix that specifies the components that comprise each system boundary. For example, the interface between the A RPCCW pump is breaker 9 on bus 34C, and indicate whether that interface component is explicitly modeled.

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A11	INCORPORATE the effect of variable success criteria (i.e., success criteria that change as a function of plant status) into the system modeling. Example causes of variable system success criteria are: • different accident scenarios. Different success criteria are required for some systems to mitigate different accident scenarios (e.g., the number of pumps required to operate in some systems is dependent upon the modeled initiating event); • dependence on other components. Success criteria for some systems are also dependent on the success of another component in the system (e.g., operation of additional pumps in some cooling water systems is required if noncritical loads are not isolated);	Nearly all of the MPS3 system models include multiple top events to represent different functions and/or success criteria. For example, the RHR model includes loss of flow to 1/3 cold legs for large LOCA and loss of flow to 2/3 cold legs for LP injection after SG cooldown for LOCAs other than large.		Note that there are assumptions included for the CHG and SI systems (Category 9 in Table 1 of Volume SY.2) that only cold leg injection phase success criteria are modeled, since the success criteria for LPR (to 1/3 cold legs) and HPR (2/3) would be dominated by the injection phase criteria (3/3). In the model however, HPR is modeled for large, medium and small LOCAs. The assumptions should be updated as necessary to reflect the current model or any necessary model changes.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A11 (contd)	• time dependence. Success criteria for some systems are time-dependent (e.g., two pumps are required to provide the needed flow early following an accident initiator, but only one is required for mitigation later following the accident); • sharing of a system between units. Success criteria may be affected when both units are challenged by the same initiating event (e.g., LOOP).			

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A12	INCLUDE in the system model those failures of the equipment and components that would affect system operability (as identified in the system success criteria), except when excluded using the criteria in SYA14. This equipment includes both active components (e.g., pumps, valves, and air compressors) and passive components (e.g., piping, heat exchangers, and tanks) required for system operation.	The system models include multiple failure modes for most components, and all modeled components and associated failure modes are documented in the system components (Section 2.4.6). Assumptions regarding components or failure modes excluded from the model are documented in the assumptions table (Table 1 of Volume SY.2). Passive failures such as tanks and heat exchangers are modeled, although piping and some other passive failures are not modeled for some systems (e.g., RPCCW). See category 6 assumptions in Table 1 of Volume SY.2.		Document the justification for not modeling passive failures for some systems using the specific criteria in SR SY-A14.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A13	When identifying the failures in SY-A12 INCLUDE consideration of all failure modes, consistent with available data and model level of detail, except where excluded using the criteria in SY-A14. For example: 1. active component fails to start 2. active component fails to continue to run 3. failure of a closed component to open 4. failure of a closed component to remain closed 5. failure of an open component to close 6. failure of an open component to remain open 7. active component spurious operation 8. plugging of an active or passive component 9. leakage of an active or passive component	The majority of the failure modes listed in this SR are included in the MPS3 system models. However, it is not clear if there is a distinction made between leakage (9), rupture (10), internal leakage (11), and internal rupture (12).		Provide discussion to clarify amongst the failure modes described in the assessment comment (leakage (9), rupture (10), internal leakage (11), and internal rupture (12).)

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A13 (contd)	10. rupture of an active or passive component 11. internal leakage of a component 12. internal rupture of a component 13. failure to provide signal/operate (e.g., instrumentation) 14. spurious signal/operation 15. pre-initiator human failure events (see SY-A15) 16. other failures of a component to perform its required function			

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A14	In meeting SY-A12 and SY-A13, contributors to system unavailability and unreliability (i.e., components and specific failure modes) may be excluded from the model if one of the following screening criteria is met: 1. A component may be excluded from the system model if the total failure probability of the component failure modes resulting in the same effect on system operation is at least two orders of magnitude lower than the highest failure probability of the other components in the same system train that results in the same effect on system operation.	The system notebooks include assumptions regarding components or failure modes excluded from the model (category 6 assumptions in Table 1 of Volume SY.2). Piping and some other passive failures are not modeled for some systems (e.g., RPCCW). Many of these assumptions are based on the assertion that “.The (non-modeled) failure probability was assumed to be insignificant compared to the (modeled) failure probability” or “because passive components do not contribute significantly to the unavailability of the system” or “due to the level of redundancy.“		Provide more detailed justification for excluding particular components or failure modes from the system models. For example for components omitted due to a high level of redundancy, show that the effect of these redundant failures is at least two orders of magnitude lower than the highest failure probability of the other components in the same system train, and that failure modes not modeled due to low significance contribute less than 1% of the total failure rate or probability for that component. Also see SY-A12 and -A13

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A14 (contd)	2. One or more failure modes for a component may be excluded from the systems model if the contribution of them to the total failure rate or probability is less than 1% of the total failure rate or probability for that component, when their effects on system operation are the same.			

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A18a	INCLUDE events representing the simultaneous unavailability of redundant equipment when this is a result of planned activity (see DA-C13).	It is not apparent if there are any incidents of coincident maintenance that need to be considered. MPS3 PRA Model Notebook DA.6 presents the plant-specific component-specific unavailability data. However, there is no discussion of coincident maintenance in the MPS3 PRA Model Notebooks DA or SY (i.e., are such situations possible?). One example is unavailability of the RWST that is modeled as failing both trains of quench spray. Another is operating with both PORV block valves closed, simultaneously isolating both PORVs.	Ensure that coincident maintenance situations have been identified, and if they exist, that the model properly considers the impacts of coincident maintenance.	Enhance the discussion in the MPS3 PRA Model Notebooks SY and DA to discuss the potential (or non-potential) for coincident maintenance. Note that if such maintenance can occur, some modeling changes may also be required, which could also impact system notebooks.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A19	IDENTIFY system conditions that cause a loss of desired system function, e.g., excessive heat loads, excessive electrical loads, excessive humidity, etc.	Several different conditions that can result in system failure are included in the system models. Examples include ventilation for rooms containing electrical equipment, EDGs, and certain pumps; and shedding of major loads to prevent potential EDG failure. Assumptions regarding whether a particular condition will result in system failure are documented in Table 1 of Volume SY.2. These assumptions however do not reference any basis for success given a certain system condition (e.g., the temperature in the RPCCW pump area is assumed to remain below the allowable 90-second limit with 2 charging pumps and RPCCW operating).	Perform needed analysis to provide basis for excluding ventilation from some system models, otherwise assume the components will fail without ventilation.	

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A19 (contd)		Other assumptions note that ventilation is currently not modeled for turbine building or service building electrical equipment (including all the non-vital load centers, MCCs, and DC switchboards), nor for TPCCW, instrument air, or service air. The acceptability of these assumptions were to be determined by future analysis.		

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-A20	TAKE CREDIT for system or component operability only if an analysis exists to demonstrate that rated or design capabilities are not exceeded.	In a few instances a system or equipment is credited without demonstration that rated capabilities are not exceeded, for example from the assumptions in Table 1 of Volume SY.2: -- The temperature in the RPCCW pump area is assumed to remain below the allowable 90-second limit with 2 charging pumps and RPCCW operating -- It is assumed that ventilation is not needed for turbine building or service building electrical equipment (including all the non-vital load centers, MCCs, and DC switchboards, or for TPCCW, instrument air or service air, the acceptability of these assumptions was to be determined by future analysis.	Perform needed analysis to provide basis for excluding ventilation from some system models, otherwise assume the components will fail without ventilation. See SY-A19 also.	

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-B3	ESTABLISH common cause failure groups by using a logical, systematic process that considers similarity in: • service conditions • environment • design or manufacturer • maintenance JUSTIFY the basis for selecting common cause component groups. Candidates for common cause failures include, for example: • motor-operated valves • pumps • safety-relief valves • air-operated valves • solenoid-operated valves • check valves • diesel generators • batteries • inverters and battery charger • circuit breakers	Common cause failures are modeled for all of the candidate equipment (except chargers and inverters) listed in this SR as well as for transformers, PORVs, screens and filters, and hydraulic valves. The modeled failures are documented in the system notebooks. However, there is no discussion of the systematic process used to establish the CCF groups. The resolution of F&O DA-12 resulted in inclusion of CCF events for batteries, transformers and reactor trip breakers.		Document the systematic process used to establish the CCF groups. An open item (DA-4) still exists to provide justification for not modeling CCFs of EDGs and SBO diesel. However, there is documentation in the EP assumptions (Category 3 in Table 1 of Volume SY.2) that the EDGs and SBO diesel have a different design, different manufacturer, are tested and maintained on separate intervals, and are located in different areas of the site. It would appear that this information provides the basis for not including a CCF for these components.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-B6	PERFORM engineering analyses to determine the need for support systems that are plant-specific and reflect the variability in the conditions present during the postulated accidents for which the system is required to function.	In a few instances support systems are assumed not to be required without an engineering analysis referenced to determine the systems are not needed, for example from the assumptions in Table 1 of Volume SY.2: -- The temperature in the RPCCW pump area is assumed to remain below the allowable 90-second limit with 2 charging pumps and RPCCW operating -- It is assumed RHR seal cooling is not needed during large LOCA due to the short mission time -- It is assumed that ventilation is not needed for turbine building or service building electrical equipment (including all the non-vital load centers, MCCs, and DC switchboards), or for TPCCW, instrument air or service air, the acceptability of these assumptions was to be determined by future analysis.	Perform needed engineering analysis to provide basis for excluding certain support systems from some system models, otherwise assume the components will fail without the supports. See SY-A19 and -A20 also.	

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-B7	BASE support system modeling on realistic success criteria and timing, unless a conservative approach can be justified, i.e., if their use does not impact risk significant contributors.	See SY-B6	See SY-B6	
SY-B14	Some systems use components and equipment that are required for operation of other systems. INCLUDE components that, using the criteria in SY-A14, may be screened from each system model individually, if their failure affects more than one system (e.g., a common suction pipe feeding two separate systems).	The system notebooks include assumptions regarding components or failure modes excluded from the model (category 6 assumptions in Table 1 of Volume SY.2). Piping and some other passive failures are generally not modeled for most systems. Many of these assumptions are based on the assertion that "... passive components do not contribute significantly to the unavailability of the system". In the case of ECCS systems however, passive piping failures may affect several systems including CHS, QSS, RHS, RSS, etc. (Note that passive failure of the RWST is modeled.)	Consider modeling passive piping (or other) failures that affect more than one system, or provide justification for not doing so.	

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-B15	IDENTIFY SSCs that may be required to operate in conditions beyond their environmental qualifications. INCLUDE dependent failures of multiple SSCs that result from operation in these adverse conditions. Examples of degraded environments include: (a) LOCA inside containment with failure of containment heat removal (b) safety relief valve operability (small LOCA, drywell spray, severe accident) (for BWRs) (c) steam line breaks outside containment (d) debris that could plug screens/filters (both internal and external to the plant) (e) heating of the water supply (e.g., BWR suppression pool, PWR containment sump) that could affect pump operability (f) loss of NPSH for pumps (g) steam binding of pumps	A few examples where consideration was given to adverse operating conditions have been identified in the systems analysis. Both QSS and RSS are modeled for their functions to maintain containment integrity (the QSS will quench steam from a pipe break). The RSS model reflects the fact that all four pumps are now aligned to provide recirc spray rather than core cooling to limit the amount of time the EEQ temperature envelope is exceeded. Common cause failure of the SW system due to debris or other conditions in the intake structure is not modeled due to detailed surveillance and response procedures. However, there are no other SSCs identified that may encounter adverse conditions. The current system notebooks describe the system components, but there is no discussion of component operability and design limits.		It is suggested a separate table of system information be developed for the various system models to document component operability and design limits (See SY-A3), and identify cases in which those limits may be exceeded.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-C2	DOCUMENT the system functions and boundary, the associated success criteria, the modeled components and failure modes including human actions, and a description of modeled dependencies including support system and common cause failures, including the inputs, methods, and results. For example, this documentation typically includes: (a) system function and operation under normal and emergency operations (b) system model boundary (c) system schematic illustrating all equipment and components necessary for system operation (d) information and calculations to support equipment operability considerations and assumptions (e) actual operational history indicating any past problems in the system operation	The MPS3 systems analysis is documented in an updated series of system notebooks that have a common content and format, and are structured to correspond to the requirements of this standard. In addition, the system dependencies, assumptions and success criteria are documented in a set of tables common to all systems. These notebooks include much of the information listed in this SR. However, in some areas the content of the system notebooks could be enhanced to better document compliance with particular SRs. In addition not all system notebooks have yet been approved.		Complete approval process for all system notebooks. Provide/enhance documentation of the following items (reference to item as listed in this SR): • Components that comprise each system boundary (i.e., which system are boundary components included in) (b) • Component operability and design limits and cases in which those limits may be exceeded (d) • Engineering analysis to provide basis for excluding certain support systems from some system models (d) • Actual operational history (e) • TM requirements and procedures (h) • Spatial information (j) • More detailed justification for excluding particular components or failure modes from the system models (l)

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-C2 (contd)	(f) system success criteria and relationship to accident sequence models (g) human actions necessary for operation of system (h) reference to system-related test and maintenance procedures (i) system dependencies and shared component interface (j) component spatial information (k) assumptions or simplifications made See ASME for remaining requirement.			• Justification for not modeling passive failures for some systems using the specific criteria in SR SY-A14 (l) • Results of system model evaluation (o) • Walkdown checklists and interview notes (q) • Identify all pertinent information sources, including the version on which the analysis is based and the current version (if different) (q) • A key to the basic event naming scheme (s) • Guidelines for component boundary definitions and specific boundaries of any components that differ from those general guidelines • Applicable operating procedures • The systematic process used to establish the CCF groups

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
SY-C3	DOCUMENT the key assumptions and key sources uncertainty associated with the systems analysis.	Although the assumptions associated with the system analysis are documented in Table 1 of Volume SY.2, this documentation does not identify which are the key assumptions related to key sources of uncertainty in the systems analysis.		Determine and document the key assumptions and key sources of uncertainty in the systems analysis.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
HR-A2	IDENTIFY, through a review of procedures and practices, those calibration activities that if performed incorrectly can have an adverse impact on the automatic initiation of standby safety equipment.	Systematic reviews of the plant systems were performed to identify sensing instruments (i.e. flow, pressure, temperature, level switches or transmitters) that provide auto-actuation signals in the system. These reviews are summarized in each of the system model notebooks. The supporting documentation for the reviews, however, is not provided or referenced. Reviews of calibration procedures are not documented. Calibration procedures applicable to the type A HREs are not documented in HR.1.		Consider assembling documentation of the systematic reviews of plant systems to identify potential mis-calibration errors (if not already assembled) and providing a cross-reference in the MPS3 PRA Model Notebook, Pre-initiator Human Failure Event Analysis, Volume HR.1. The documentation would provide inventories of all sensing instruments identified in the system P&IDs, and the basis for including them in the Type A HRA or screening them from further analysis. Include in the documentation reviews of procedures and practices that identify those calibration activities that if performed incorrectly can have an adverse impact on the sensing instruments identified from the system P&IDs.

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
HR-A3	IDENTIFY which of those work practices identified above (HR-A1, HR-A2) involve a mechanism that simultaneously affects equipment in either different trains of a redundant system or diverse systems [e.g., use of common calibration equipment by the same crew on the same shift, a maintenance or test activity that requires realignment of an entire system (e.g., SLCS)].	Some considerations of potential mis-calibration or restoration error events that simultaneously affect equipment in different trains of a redundant system are documented in MPS3 PRA Model Notebook, Pre-initiator Human Failure Event Analysis, Volume HR.1 for each Type A HRE. However, a comprehensive discussion of the potential for mis-calibration or failure to realign components of multiple trains of redundant systems and diverse systems is not provided.		Provide a comprehensive discussion of the potential for mis-calibration or failure to realign components of different trains of a redundant system and of diverse systems. For example, 1) Is common calibration equipment used by the same crew on the same shift; 2) Would multiple safety trains of a redundant system be calibrated by the same crew on the same shift; 3) Procedural dependencies may arise from procedures performed on one component/system that may impact the status of another component/system. This dependency may result from the need to isolate a component on one system to perform calibration on another;

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
HR-A3 (contd)				3) Physical dependencies applicable to mis-calibration events may arise from the incorrect identification of instrumentation to be calibrated (e.g., incorrect pressure transmitters located in the vicinity of those intended to be calibrated). 4) Does MPS3 have a rigorous component identification and tagging system that would help to preclude instrument mis-identification; 4) Are any multiple train calibrations performed with a single procedure; 5) Do technicians know of any potential issues?

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
HR-B1	If screening is performed, ESTABLISH rules for screening individual activities from further consideration. Example: Screen maintenance and test activities from further consideration only if (a) equipment is automatically re-aligned on system demand, or ((b) following maintenance activities, a post-maintenance functional test is performed that reveals misalignment, or (c) equipment position is indicated in the control room, status is routinely checked, and realignment can be affected from the control room, or (d) equipment status is required to be checked frequently (i.e., at least once a shift)	The basis for screening individual activities is summarized in the system notebooks. These rules for screening activities were generally found to be appropriate, however no consolidated list of rules is provided in the MPS3 PRA Model Notebook HR.1. Also, activities were screened in some instances on the basis that they have no or insignificant impact on PRA results. However, the quantitative basis for screening is not discussed in terms of CDF/LERF impact. For example, the potential to misalign multiple trains SG feed lines was evaluated in the MPS3 PRA Model Notebook SY.3.FW. Since the success criteria for steam generator cooling is 2 of 4 SGs, a single misalignment HEP that causes a loss of SGC would require for failing align 3 or more valves, which is considered negligible (less than 4E-6).		1) Generate and document in HR.1 a list of rules established for screening individual activities from further consideration. 2) For activities that have no or insignificant impact on PRA results, provide quantitative bases for screening activities in terms of CDF/LERF impact.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
HR-B1 (contd)		It is preferable to express quantitative arguments in terms of impact to CDF/LERF.		
HR-B2	DO NOT screen activities that could simultaneously have an impact on multiple trains of a redundant system or diverse systems (HR-A3).	The documentation of the Type A HRE identification process does not indicate whether any activities that could simultaneously have an impact on multiple trains of a redundant system or diverse systems were identified and screened.		Document in the appropriate SY.3 notebooks considerations of activities that could simultaneously have an impact on multiple trains of a redundant system or diverse systems. If any such activities exist, also document that they have been retained and modeled by the HRA.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
HR-C2	INCLUDE those modes of unavailability that, following completion of each unscreened activity, result from failure to restore (a) equipment to the desired standby or operational status (b) initiation signal or set point for equipment start-up or realignment (c) automatic realignment or power ADD failure modes identified during the collection of plant-specific or applicable generic operating experience that leave equipment unavailable for response in accident sequences.	Potential failure modes considered in the analysis include failure to restore: (a) equipment to the desired standby or operational status, (b) initiation signal or set point for equipment start-up or realignment. However, no documentation was found of considerations of the failure to restore automatic realignment or power. Also, no discussion is provided in MPS3 PRA Model Notebook, Pre-initiator Human Failure Event Analysis, Volume HR.1.of a review for such failure modes as part of the collection of plant-specific or applicable generic operating experience.	Examine and document plant-specific or applicable generic operating experience that leave equipment unavailable for response in accident sequences.	Include consideration of modes of unavailability resulting from failure restore: 1) automatic realignment or 2) electrical power.
HR-C3	INCLUDE the impact of miscalibration as a mode of failure of initiation of standby systems.	The impact of miscalibration as a mode of failure of initiation of standby systems has been included in the PRA. However, supporting documentation for the reviews to identify or screen mis-calibration errors is not referenced.		Assemble documentation of the systematic reviews of plant systems to identify mis-calibration errors (if not already assembled) and provide cross-references in the appropriate MPS3 PRA Model Notebook(s).

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
HR-D3	For each detailed human error probability assessment, INCLUDE in the evaluation process the following plant-specific relevant information: (a) the quality of written procedures (for performing tasks) and administrative controls (for independent review) (b) the quality of the human-machine interface, including both the equipment configuration, and instrumentation and control layout	No documentation was found that discusses the quality of written procedures, administrative controls or the quality of the human-machine interface.		As part of the pre-initiator HEP evaluations, document the evaluation process of the following plant-specific relevant information: (a) the quality of written procedures (for performing tasks) and administrative controls (for independent review), (b) the quality of the human-machine interface, including both the equipment configuration, and instrumentation and control layout.
HR-E1	When identifying the key human response actions REVIEW: (a) the plant-specific emergency operating procedures, and other relevant procedures (e.g., AOPs, annunciator response procedures) in the context of the accident scenarios (b) system operation such that an understanding of how the system(s) functions and the human interfaces with the system is obtained	The methodology for identifying key human response actions is documented in HRA PRA Manual, PRAM-2E (Rev. 0, February 2005) and complies with this SR. However discussion of the implementation of this methodology for MPS3 is not provided in the MPS3 PRA Model Notebook HR.1.		Provide documentation of the process employed to identify MPS3 key human response actions (i.e., the Type C human reliability events).

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
HR-G3	When estimating HEPs EVALUATE the impact of the following plant-specific and scenario-specific performance shaping factors: (a) quality [type (classroom or simulator) and frequency] of the operator training or experience (b) quality of the written procedures and administrative controls (c) availability of instrumentation needed to take corrective actions (d) degree of clarity of the cues/indications (e) human-machine interface (f) time available and time required to complete the response (g) complexity of the required response (h) environment (e.g., lighting, heat, radiation) under which the operator is working (i) accessibility of the equipment requiring manipulation (j) necessity, adequacy, and availability of special tools, parts, clothing, etc.	Certain plant-specific and scenario-specific performance shaping factors are evaluated as part of the caused-based analysis of cognition failure probabilities (Pc). However, the effect of performance-shaping factors on the selection of appropriate execution stress levels have not been documented.		For each Type C human reliability event (and Type B events, if applicable), justify the execution stress level selected for each human error probability calculation. Include the impact on execution stress levels from plant-specific and scenario-specific performance shaping factors, which include: (a) quality [type (classroom or simulator) and frequency] of the operator training or experience (b) quality of the written procedures and administrative controls (c) availability of instrumentation needed to take corrective actions (d) degree of clarity of the cues/indications (e) human-machine interface (f) time available and time required to complete the response (g) complexity of the required response (h) environment (e.g., lighting, heat, radiation) under which the operator is working

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
HR-G3 (contd)				(i) accessibility of the equipment requiring manipulation (j) necessity, adequacy, and availability of special tools, parts, clothing, etc.
HR-G6	CHECK the consistency of the post-initiator HEP quantifications. REVIEW the HFEs and their final HEPs relative to each other to check their reasonableness given the scenario context, plant history, procedures, operational practices, and experience.	The PRA notebooks do not document a review of the HFEs and their final HEPs relative to each other to check reasonableness given the scenario context, plant history, procedures, operational practices, and experience.		Document a review of the HFEs and their final HEPs relative to each other to confirm their reasonableness given the scenario context, plant history, procedures, operational practices, and experience.
DA-B2	DO NOT INCLUDE outliers in the definition of a group (e.g., do not group valves that are never tested and unlikely to be operated with those that are tested or otherwise manipulated frequently)	The DA.2 calculation was reviewed to determine if any outlier components were inappropriately included in the established groupings. While it did not appear that outliers were included in any groups, there was no specific documentation to indicate this fact or to indicate that a conscious effort was made to ensure that outlier inclusion did not occur.		The MPS3 PRA Model Notebook DA.2 discussion of how the component data was developed should be enhanced to include a specific discussion of outlier treatment (i.e., do any outliers exist? If so, how are these events considered and grouped?).

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
DA-C8	When required, USE plant-specific operational records to determine the time that components were configured in their standby status.	MPS3 PRA Model Notebook DA.4 documents the development of the data for the PRAs alignment-specific events. The current approach used for these events meets Capability Category 1, in that the PRA assumes an overall average distribution of system alignments. The estimates used are reasonable. However, this approach does not meet Category 2 requirements.	Develop alignment-specific basic event values based on actual plant operating experience.	

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
DA-C10	When using surveillance test data, REVIEW the test procedure to determine whether a test should be credited for each possible failure mode. COUNT only completed tests or unplanned operational demands as success for component operation. If the component failure mode is decomposed into sub-elements (or causes) that are fully tested, then USE tests that exercise specific sub-elements in their evaluation. Thus, one sub-element sometimes has many more successes than another. [Example: a diesel generator is tested more frequently than the load sequencer. IF the sequencer were to be included in the diesel generator boundary, the number of valid tests would be significantly decreased.]	There is no evidence in MPS3 PRA Model Notebook DA.2 that a review of the actual surveillance tests were made to determine if certain tests only exercised certain sub-components. There is no evidence that the current data analysis is invalid or improperly considered the test data. However, there is no documentation to specifically verify that this SR has been met.		Include documentation in MPS3 PRA Model Notebook DA.2 concerning the review of surveillance tests to ensure that the proper number of demands have been assigned to each failure mode, etc.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
DA-C13	EXAMINE coincident unavailability due to maintenance for redundant equipment (both intrasystem and intersystem) based on actual plant experience. CALCULATE coincident maintenance unavailabilities that reflect actual plant experience. Such coincident maintenance unavailability can arise, for example, for plant systems that have “installed spares,” i.e., plant systems that have more redundancy than is addressed by tech specs. For example, the charging system in some plants has a third train that may be out of service for extended periods of time coincident with one of the other trains and yet is in compliance with tech specs.	It is not certain if there are any incidents of coincident maintenance that need to be considered. MPS3 PRA Model Notebook DA.6 presents the plant-specific component-specific unavailability data. However, there is no discussion of coincident maintenance (i.e., are such situations possible? if so, what is the historical record for such events?). One possible example of potential coincident maintenance at MPS3 may be the blocking of more than one PORV (or declaring a PORV inoperable) at a given time.	Ensure that coincident maintenance situations have been identified, and if they exist, that the model and data properly consider the impacts of coincident maintenance.	Enhance the discussion in MPS3 PRA Model Notebook DA.6 to discuss the potential 9or non-potential) for coincident maintenance. Note that if such maintenance can occur, some modeling changes may also be required, which could also impact system notebooks.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
DA-D4	When the Bayesian approach is used to derive a distribution and mean value of a parameter, CHECK that the posterior distribution is reasonable given the relative weight of evidence provided by the prior and the plant-specific data. Examples of tests to ensure that the updating is accomplished correctly and that the generic parameter estimates are consistent with the plant-specific application include the following: (a) confirmation that the Bayesian updating does not produce a posterior distribution with a single bin histogram (b) examination of the cause of any unusual (e.g., multimodal) posterior distribution shapes (c) examination of inconsistencies between the prior distribution and the plant-specific evidence to confirm that they are appropriate	MPS3 PRA Model Notebook DA.2 includes an assessment of the difference between the updated mean values to the original generic (prior) data. An analysis is provided of the possible reasons for the larger variances that were observed. Also, the notebook includes plots of the prior and updated distributions for each event, which would indicate a “single bin histogram” or multimodal condition and other anomalies. However, the documentation does not discuss whether or not a specific review was performed on the data for each of these various tests that are recommended in this SR.		The MPS3 PRA Model Notebook DA.2 documentation should be expanded to discuss the other consistency/applicability tests on the Bayesian-updated events as defined in this SR.

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	**Category II**	**Assessment Comments**	**Model Enhancement**	**Documentation Enhancement**
DA-D4 (contd)	(d) confirmation that the Bayesian updating algorithm provides meaningful results over the range of values being considered (e) confirmation of the reasonableness of the posterior distribution mean value			
DA-D6	USE generic common cause failure probabilities consistent with available plant experience. EVALUATE the common cause failure probabilities consistent with the component boundaries.	While the alpha factors used for MPS3 are based on recent generic estimates (and appear to be appropriate), there is no discussion in the MPS3 PRA Model Notebook DA.3 to indicate that the alpha factors were checked for consistency with plant operating experience.		Provide documentation in the MPS3 PRA Model Notebook DA.3 to demonstrate that the generic factors were reviewed against plant-specific operating experience to ensure that the generic factors are appropriate.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IF-B2	For each potential source of flooding water, IDENTIFY the flooding mechanisms that would result in a fluid releaser. INCLUDE: (a) failure modes of components such as pipes, tanks, gaskets, expansion joints, fittings, seals, etc. (b) human-induced mechanisms that could lead to overfilling tanks, diversion of flow through openings created to perform maintenance; inadvertent actuation of fire suppression system (c) other events releasing water into the area	Three categories of flooding initiating events were evaluated for the potential flood sources identified: tank rupture, system pipe rupture, and maintenance-related events. However, it does not appear that failure of gaskets, expansion joints, fittings, seals or other components were considered. In addition, although a method for maintenance-induced flood events is described in the Flooding Initiating Events Notebook, no such scenarios were explicitly evaluated in the documentation. Inadvertent fire sprinkler actuation also does not appear to be considered.	Identify flooding sources that may result in fluid release due to failure of other (non-piping) components, human error during maintenance, or inadvertent sprinkler actuation.	Complete review and approval of the Flooding Initiating Events Notebook.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IF-C3b	IDENTIFY inter-area propagation through the normal flow path from one area to another via drain lines; and areas connected via back flow through drain lines involving failed check valves, pipe and cable penetrations (including cable trays), doors, stairwells, hatchways, and HVAC ducts. INCLUDE potential for structural failure (e.g., of doors or walls) due to flooding loads.	Based on a review of the draft IF PRA notebooks, inter-area propagation flow paths are appropriately identified and account for: 1) potential structural failure due to flooding loads, 2) propagation via penetrations, doors, stairwells, hatchways and HVAC ducts. No summary discussion of the locations of floor drain check valves and considerations for their potential failure was found.		Provide a summary discussion of the locations of floor drain check valves and the considerations for their potential failure.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IF-C4a	For multi-unit sites with shared systems or structures, INCLUDE multi-unit scenarios.	No credible multi-unit scenarios exist. 1) MPS2 and MPS3 share in common an electrical switchyard and a station blackout diesel. Internal flooding scenarios are not applicable to the switchyard. The SBO diesel is located in a stand-alone building in the yard that communicates with no other parts of the plant. No credible internal flooding initiating events were identified for the building that houses the SBO diesel. 2) Also, communication exists between the plants via the water treatment facility. More discussion is suggested to describe that no credible flood propagation paths exist via this pathway.		Document in more detail that no credible flood propagation paths between the plants exist via the water treatment facility.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IF-C8	USE potential human mitigative actions as additional criteria for screening out flood sources if all the following can be shown: (a) flood indication is available in the control room; (b) the flood source can be isolated; and (c) the mitigative action can be performed with high reliability for the worst flood from that source. High reliability is established by demonstrating, for example, that the actions are procedurally directed, that adequate time is available for response, that the area is accessible, and that there is sufficient manpower available to perform the actions.	The screening of flood areas generally complies with this SR, based on a review of the MPS3 PRA Model Notebook IF.2, "Internal Flooding Accident Sequence Analysis," (Revision Draft C, September 2004). In some cases a flood isolation action is assumed to be successful due to the availability of several hours to isolate the leak. However, discussions of applicable flood isolation procedures, in these instances were not included.		For any human mitigative actions used as criteria for screening out flood sources on the basis that the actions can be performed with high reliability (i.e., where significant time was available to perform the action), reference the applicable flood isolation operating procedure.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IF-D5	DETERMINE the flood-initiating event frequency for each flood scenario group by using the applicable requirements in Table 4.5.1-2(c).	Based on a review of Draft B of MPS3 PRA Model Notebook IE.1, the flood-initiating event frequency for each flood scenario group appears to be calculated using the applicable IE supporting requirements (Table 4.5.1-2c of Addendum B). However, the documentation does not indicate that the initiating event frequencies are computed in terms of reactor years		Provide clarification in the IF PRA documentation that the initiating event frequencies are calculated in units of reactor years. Document the basis for the availability factor used to convert initiating event frequencies to events per reactor year, or provide a cross reference.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
IF-D5a	GATHER plant-specific information on plant design, operating practices, and conditions that may impact flood likelihood (i.e., material condition of fluid systems, experience with water hammer, and maintenance-induced floods). In determining the flood-initiating event frequencies for flood scenario groups, USE a combination of (a) generic and plant-specific operating experience; (b) pipe, component, and tank rupture failure rates from generic data sources and plant-specific experience; and (c) engineering judgment for consideration of the plant-specific information collected.	No documentation of the consideration of plant-specific flooding experience was found in the draft IF PRA notebooks.		Document or reference the review of plant-specific internal flooding experience (e.g., experience with water hammer, steam leaks, and maintenance-induced floods), and include how the findings were applied to the initiating events frequency analysis.
IF-D6	INCLUDE consideration of human-induced floods during maintenance through application of generic data.	Consideration of human-induced floods was not provided in the draft documentation.	Include consideration of human-induced floods in the internal flooding PRA.	

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
QU-B1	PERFORM quantification using computer codes that have been demonstrated to generate appropriate results when compared to those from accepted algorithms. IDENTIFY method-specific limitations and features that could impact the results.	CAFTA is used to develop the different model elements (fault trees, event trees, basic event data file, etc.). The model (an accident sequence fault tree that is developed from the event trees) is solved using PRAQUANT to obtain risk metrics such as CDF, LERF, importance data, and sequence contributions. CAFTA is a PRA development and analysis application developed and maintained by EPRI that is widely used throughout the nuclear and aerospace industries for performing risk analysis. Method-specific limitations and features that could impact results are not identified, instead the Users Manual is given as reference for this information.		Identify and document method-specific limitations and features that could impact results.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
QU-D1c	REVIEW results to determine that the flag event settings, mutually exclusive event rules, and recovery rules yield logical results.	While the MPS3 PRA Model Notebook QU.1 Model Quantification Inputs, describes the application of mutually-exclusive logic and recovery rules (flag settings are not used, see QU-B8), there is no discussion of any review performed to verify the mutually exclusive events and recovery rules are applied properly and give logical results. The previous version (R1) of the MPS3 PRA Model Notebook QU.2 Quantification Results did include some discussion of the impact of specific MEX and recovery rules, as part of the discussion of the focused review, but there was no systematic review performed to ensure the rules were applied correctly to provide logical results.		Perform and document a review of the model results to verify the MEX and recovery rules are applied properly and give logical results.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
QU-D3	COMPARE results to those from similar plants and IDENTIFY causes for significant differences. For example: Why is LOCA a large contributor for one plant and not another?	The current version (R2) of the MPS3 PRA Model Notebook QU.2 provides a list of plant features that influence risk, but no comparison of results with similar plants. The previous version of the notebook included a comparison of the CDF contributors with two other Dominion Westinghouse PWRs, some possible reasons for the differences, and the list of plant features that influence risk. In some cases only the difference is noted, and not the cause for the difference.		Identify and document possible causes for significant differences. Consider expanding the comparison to plants outside the Dominion fleet.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
QU-D4	REVIEW a sampling of nonsignificant accident cutsets or sequences to determine they are reasonable and have physical meaning.	While the MPS3 PRA Model Notebook QU.2 lists all of the accident sequence results, only the top 4 are described, and only the top 50 cutsets are listed in the current version (R2) notebook. The previous version (R1) listed the top 100 accident sequences, provided a description of the top 5 sequences (which contribute at least 5% of CDF), and also listed the top 100 cutsets and described the top 5 cutsets. There is no evidence of any review performed of non significant cutsets or sequences (i.e., which sequences/cutsets were reviewed, the method of the review, the description of those cutsets, or results/insights from the review, etc.).		Perform and document a review of a sample of the nonsignificant sequences/cutsets.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
QU-D5a	IDENTIFY significant contributors to CDF, such as initiating events, accident sequences, equipment failures, common cause failures, and operator errors. INCLUDE SSCs and operator actions that contribute to initiating event frequencies and event mitigation.	The MPS3 PRA Model Notebook QU.2 (R1 and R2) lists the contribution from all accident sequences, and importance measures for the top initiators, basic events, and operator actions. The list of most important initiating event contributors includes several SSC failures that contribute to IEFs, such as fuse failures that cause loss of a vital AC bus, SW pump random failures and SW screen common cause failures that cause a loss of SW. The results do not include a list of CCFs that are significant failures.		Identify and document common cause failures that are significant contributors to CDF.

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SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
QU-D5b	REVIEW the importance of components and basic events to determine that they make logical sense.	The current version (R2) of the MPS3 PRA Model Notebook QU.2 lists top initiators, basic events, and operator actions based on importance measures. The previous version (R1) includes a discussion comparing the importance results from the latest update to those from the previous update. While the comparison includes the reasons for the changes in importance measures, there is no discussion of a systematic review performed to verify the importance results make logical sense from a model consistency standpoint (e.g., symmetrical initiating events and basic events have similar importance results).		Perform and document a systematic review of the importance measures to determine they make logical sense.

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
QU-F3	DOCUMENT the significant contributors (such as initiating events, accident sequences, basic events) to CDF in the PRA results summary. PROVIDE a detailed description of significant accident sequences or functional failure groups.	Although the MPS3 PRA Model Notebook QU.2 documents the initiating events and accident sequences that are significant contributors to CDF, as well as the most important basic events, only 4 accident sequences are briefly described. There is no detailed description of significant accident sequences or functional failure groups.		Provide a detailed description of significant accident sequences or functional failure groups.
QU-F5	DOCUMENT limitations in the quantification process that would impact applications.	The MPS3 PRA Model Notebooks QU.1 and QU.2 do not provide any discussion of limitations of the quantification process.	Resolve open item to evaluate (a)(4) impact of model limitations.	Provide discussion of any limitations in the quantification process that would impact applications.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
QU-F6	DOCUMENT the quantitative definition used for significant basic event, significant cutset, significant accident sequence. If other than the definition used in Section 2, JUSTIFY the alternative.	The MPS3 PRA Model Notebooks QU.1 and QU.2 do not provide indication of the quantitative definition used for significant basic event, significant cutset, and significant accident sequence. However, based on the accident sequences which are discussed (a total of 4 contributing greater than 7.5% individually and comprising less than 50% of the total CDF), the cutsets listed (those contributing greater than 0.1% individually but comprising just over 50% of the total CDF), and the basic event importance measures listed (RAW greater than 5), it appears that the definition of "significant" used is not consistent with that in this standard.		Expand the results discussion in the notebooks to include those within the standard definition for significant basic event, significant cutset, and significant accident sequence; or document (and provide justification for using) an alternate definition.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-A5	DEFINE plant damage states consistent with LE-A1, LE-A2, LE-A3, and LE-A4.	The Millstone PRA is solved using a CAFTA model that presumably appropriately assigns a PDS for each accident sequence. However, the assignment of these sequences should be documented in a readily reviewable calculation (i.e., a LERF notebook)		Develop a LERF notebook and document the PDS assignments for the CAFTA sequences. Although the PDS assignments could not be reviewed in this assessment, it is assumed that they have been performed appropriately, so this enhancement is considered a documentation enhancement.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-B2	DETERMINE the containment challenges (e.g., temperature, pressure loads, debris impingement) resulting from contributors identified in LE-B1 using applicable generic or plant-specific analyses for significant containment challenges. USE conservative treatment or a combination of conservative and realistic treatment for non-significant containment challenges. If generic calculations are used in support of the assessment, JUSTIFY applicability to the plant being evaluated.	A plant-specific containment analysis is summarized in PSS Section 4.4 (reference is also made to PSS appendices 4-F and 4-G). This analysis was used appropriately for the Level 2 analysis. However, core debris impingement need also be addressed for completeness.		Include an assessment of core debris impingement as a potential failure mode (listed here as a documentation enhancement, assuming that it will not be a factor. If it is, then it would require a model enhancement).

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-C3	INCLUDE model logic necessary to provide a realistic estimation of the significant accident progression sequences resulting in a large early release. INCLUDE mitigating actions by operating staff, effect of fission product scrubbing on radionuclide release, and expected beneficial failures in significant accident progression sequences. PROVIDE technical justification (by plant-specific or applicable generic calculations demonstrating the feasibility of the actions, scrubbing mechanisms, or beneficial failures) supporting the inclusion of any of these features.	The MPS3 PSS Section 4.7 quantified the branch nodes of the CET for various plant configurations. However, the model files are not available for solution, and MPS3 should have the capability to modify and analyze the Level 2 analysis.	Build computer models to allow solution of a CET that meets the ASME standard requirements described in element LE-C1 and LE-C2A/B.	

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-C8a	JUSTIFY any credit given for equipment survivability or human actions under adverse environments.	No discussion of equipment survivability or human actions under adverse environments was presented.		Document equipment survivability in the extreme environments. This is listed as a documentation enhancement because it is not expected that the evaluation will not identify any items that impact the model.
LE-C8b	REVIEW significant accident progression sequences resulting in a large early release to determine if engineering analyses can support continued equipment operation or operator actions during accident progression that could reduce LERF. USE conservative or a combination of conservative and realistic treatment for non-significant accident progression sequences.	Equipment survivability was not addressed (see element LE-C8a). Should the LE-C8a evaluation identify any limits to credit for equipment survivability or operator actions, then the analysis should consider if such equipment/operator actions could still receive some credit.		Equipment survivability was not addressed (see element LE-C8a). Should the LE-C8a evaluation identify any limits to credit for equipment survivability or operator actions, then the analysis should consider if such equipment/operator actions could still receive some credit.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-C9a	JUSTIFY any credit given for equipment survivability or human actions that could be impacted by containment failure.	No assessment of equipment survivability after containment failure is presented.		Consider equipment survivability or human actions after containment failure. If none are credited, then a statement indicating such can be added to the LERF documentation.
LE-C9b	REVIEW significant accident progression sequences resulting in a large early release to determine if engineering analyses can support continued equipment operation or operator actions after containment failure that could reduce LERF. USE conservative or a combination of conservative and realistic treatment for non-significant accident progression sequences.	No review of the dominant LERF sequences for such credit was discussed in the MPS3 Level 2 documentation.		Review the dominant LERF sequences for possible credit for containment systems and/or operator actions after containment failure that could potentially reduce LERF. This item is listed as a documentation recommendation as it is not expected that the review would identify any items.

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-D1b	EVALUATE the impact of accident progression conditions on containment seals, penetrations, hatches, drywell heads (BWRs), and vent pipe bellows. INCLUDE these impacts as potential containment challenges, is required. If generic analyses are used in support of the assessment, JUSTIFY applicability to the plant being evaluated.	The plant specific containment assessment described in Section 4.4.1 of the PSS presented the ultimate containment capacity, but did not discuss any review of the effect on containment penetrations, seals or the hatch, etc.		It is not likely that a review of the containment penetrations, seals, hatch, etc. will affect the containment failure analysis, but an assessment of these should be added to the documentation.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-D6	PERFORM containment isolation analysis in a realistic manner for the significant accident progression sequences resulting in a large early release. USE conservative or a combination of conservative or realistic treatment for the non-significant accident progression sequences resulting in a large early release. INCLUDE consideration of both the failure of containment isolation systems to perform properly and the status of safety systems that do not have automatic isolation provisions.	Containment isolation, which is addressed separately in the CET, is taken to be independent of the Level 1 systems (per PSS Section 4.7.1.1.1, the subatmospheric design is assumed to make any pre-existing isolation pathway not credible, and assigned a low probability). In the PSS Section 4.7.1.1.1, the conditional probability of CI failure was 1E-4, while in the C-Matrix Table 4.7.2-2 and in PRA00YQA-01822S3, section I-6-17, the probability is 2E-4.		Perform an evaluation of all Tech Spec containment penetrations to ensure that all potential isolation failure pathways have been considered. The basis for the conditional probability used in the analysis should be clear in the LERF documentation.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-E4	QUANTIFY LERF consistent with the applicable requirements of Tables 4.5.8-2(a), 4.5.8-2(b), and 4.5.8-2(c). NOTE: The supporting requirements in these tables are written in CDF language. Under this requirement, the applicable quantification requirements in Table 4.5.8-2 should be interpreted base on the approach taken for the LERF model. For example, supporting requirement QU-A2 addresses the calculation of point estimate/mean CDF. Under this requirement, the application of QU-A2 would apply to the quantification of point estimate/mean LERF.	The CET split fractions are quantified in the PSS Section 4.7.1. The conditional probabilities of large, early release (CPLERs) are presented in PRA00YQA-01822S3, Section I-6-17, which takes the results of the PSS Table 4.7.2-2. The Level 2 analysis cannot be requantified at MPS3 (no computer files available), but the LERF is calculated by utilizing the CPLERs of each PDS in the EOOS model.		The requirements of tables 4.5.8-2a, b and c involve detailed evaluation and documentation of the LERF calculation. The EOOS solution presents the total mean LERF and LERF cutsets can be examined, but a more detailed documentation is required to meet the Standard.
LE-F1b	REVIEW contributors for reasonableness (e.g., to assure excessive conservatisms have not skewed the results, level of plant specificity is appropriate for significant contributors, etc.).	No review of the contributors for reasonableness was provided in the MPS3 LERF documentation.		In the LERF documentation, provide a discussion of the results for overall reasonableness.

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-F2	PROVIDE uncertainty analysis that identifies the key sources of uncertainty and includes sensitivity studies for the significant contributors to LERF.	Section 4.7.4.2 of the PSS provides a good review of some significant areas of uncertainty in the overall Level 2 evaluation. However, the ASME Standard requires a review specifically related to the key LERF uncertainties, which has not been done.		Perform uncertainty/sensitivity analyses on the significant contributors to LERF.

Table A.2.2-2 Supporting Requirements Determined <u>Not</u> to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-F3	IDENTIFY contributors to LERF and characterize LERF uncertainties consistent with the applicable requirements of Tables 4.5.8-2(d) and 4.5.8-2(e). NOTE: The supporting requirements in these tables are written in CDF language. Under this requirement, the applicable requirements of Table 4.5.8 should be interpreted based on LERF, including characterizing key modeling uncertainties associated with the applicable contributors from Table 4.5.9-3. For example, supporting requirement QU-D5 addresses the significant contributors to CDF. Under this requirement, the contributors would be identified based on their contribution to LERF.	Tables 4.5.8-2 d and e of the ASME Standard include requirements such as comparing the overall LERF and LERF dominant contributors to similar plants, and evaluating the overall LERF uncertainty intervals. These have not been performed for MPS3	Develop the uncertainty capabilities for the LERF model.	Compare LERF results and uncertainties to similar plants and include in the LERF documentation.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-G1	DOCUMENT the LERF analysis in a manner that facilitates PRA applications, upgrades, and peer review.	The bulk of the LERF analysis is contained in the PSS Section 4 (all Level 2), which has not been updated since 1983. The calculation PRA00YQA-01822S3 volume 4 discusses taking the LERF conditional probabilities from the PSS and integrating it in the EOOS model to provide LERF point estimates.		A LERF notebook could be established that identifies the key factors in the LERF model, including dominant contributors, key areas of uncertainty, and detailed review of the results for overconservatism. It could be structured in such a way that it would clearly identify how the requirements of the ASME PRA Standard are met. This would facilitate review and identification of areas of uncertainty that might be key in certain applications.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-G2	DOCUMENT the process used to identify plant damage states and accident progression contributors, define accident progression sequences, evaluate accident progression analyses of containment capability, and quantify and review the LERF results. For example, this documentation typically includes (a) the plant damage states and their attributes, as used in the analysis (b) the method used to bin the accident sequences into plant damage states (c) the containment failure modes, phenomena, equipment failures and human actions considered in the development of the accident progression sequences and the justification for their inclusion or exclusion from the accident progression analysis	The PSS, although developed in 1983, documented well the development of the Level 2 for MPS3 including PDS considerations, CET development, etc. However, the ASME Standard deals specifically with LERF, so the LERF results and uncertainty should be documented.		Expand the Level 2 results to specifically present the LERF, its uncertainties, and sensitivities.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-G2 (contd)	(d) the treatment of factors influencing containment challenges and containment capability, as appropriate for the level of detail of the analysis (e) the basis for the containment capacity analysis including the identification of containment failure location(s), if applicable – See ASME standard for remaining portion of this requirement.			
LE-G3	DOCUMENT the relative contribution of contributors (i.e., plant damage states, accident progression sequences, phenomena, containment challenges, containment failure modes) to LERF.	Calculation PRA00YQA-01822S3, Volume IV presents the total LERF and breaks the contribution down by Release Mechanism (essentially by containment failure mode).		Calculate the relative contribution to LERF by PDS, accident progression sequences, Level 2 phenomena and containment challenges.
LE-G4	DOCUMENT key assumptions and key sources of uncertainty associated with the LERF analysis, including results and important insights from sensitivity studies.	Section 4.7.4.2 of the PSS provides a good review of some significant areas of uncertainty in the overall Level 2 evaluation. However, the ASME Standard requires a review specifically related to the key LERF uncertainties, which has not been done.		Perform uncertainty/sensitivity analyses on the significant contributors to LERF.

Table A.2.2-2 Supporting Requirements Determined Not to Impact the Results for the Power Uprate Evaluation

SR	Category II	Assessment Comments	Model Enhancement	Documentation Enhancement
LE-G5	IDENTIFY limitations in the LERF analysis that would impact applications.	No evaluation of the limitations in the LERF analysis that could impact applications was presented in the documentation.		Include in the LERF documentation an assessment that identifies the limitations in the LERF analysis that could impact applications.
LE-G6	DOCUMENT the quantitative definition used for significant accident than the definition used in Section 2, JUSTIFY the alternative.	Calculation PRA00YQA-01822S3, Section I-5-9, provides a definition of “early” as being within the first 2 hours after the event occurs. No specific definition of “large” was found.		The ASME Standard defines “large, early” as: “the rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of off-site emergency response and protective actions such that there is a potential for early health effects.“The MPS3 documentation should either adopt similar wording, or provide additional justification for deviating from the ASME definition.

2.14 Impact of SPU on Renewed Plant OL

A license renewal application (LRA) was prepared in accordance with the requirements of 10 CFR 54 for the MPS3 and was submitted to the NRC on January 20, 2004. The NRC staff reviewed the LRA for compliance with 10 CFR 54. In August 2005, the *Safety Evaluation Report - Related to the License Renewal of Millstone Power Station, Units 2 and 3,* (SER) was issued as NUREG-1838.

DNC reviews focused on the effects that the SPU had on the evaluations performed for license renewal.

The LRA and SER were reviewed to determine the impact of the SPU on license renewal. Where appropriate, each section in this Licensing Report evaluates the effect of SPU on the system, structure or component (SSCs) under review, as well as evaluating the impact to the programs that manage the aging effects on those components. This section presents summary information of the results of that review, and discusses the effects of SPU on SSCs included in the LRA but not discussed in RS-001.

2.14.1 Impact of SPU on Aging Management

The LRA credited a number of existing, modified, and new aging management programs with managing the effects of aging on systems, structures, and components (SSCs) during the period of extended operation. In NUREG-1838, the NRC included the license condition that commitments be implemented prior to the period of extended operation, and concluded that the aging management programs provide reasonable assurance that aging effects will be managed such that the intended functions of SSCs will be maintained during the license renewal period.

Table 2.1 through 2.13 of this Licensing Report summarize the impact of the SPU on plant accident response and safety, as well as discuss the impact on the license renewal regulated events (Environmental Qualification, anticipated transient without scram, station blackout, pressurized thermal shock, and fire protection) that were the basis for license renewal scoping and screening. A review of these sections of this report has been conducted and confirms that the SPU activities will not add any new components nor introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Therefore, impact from the SPU on the license renewal scoping and screening results presented in the LRA and approved by the NRC in NUREG-1838 has been addressed.

In addition, component-specific sections of this Licensing Report reviewed the impact of the SPU on the SSC aging assessments performed in the LRA. These sections concluded that no new aging effects will result from the SPU. Thus, the aging management programs presented in Appendix B of the LRA that are credited with managing the effects of aging on license renewal SSCs and approved by the NRC in NUREG-1838 remain valid for SPU conditions.

2.14.2 Impact of SPU on Time-Limited Aging Analyses

The time-limited aging analyses (TLAAs) for MPS3 are presented in Section 4.0 of the LRA. The NRC concluded in NUREG-1838 that the LRA included the list of TLAAs as defined in 10 CFR 54.3. The staff also concluded that the TLAAs have been demonstrated to remain valid for the period of extended operation, as required by 10 CFR 54.21 (c)(1)(i), or have been projected to the end of the period of extended operation, as required by 10 CFR 54.21 (c)(1)(ii), or that the aging effects are adequately managed for the period of extended operation in accordance with 10 CFR 54.21 (c)(1)(iii).

The impacts of the SPU on the TLAAs are discussed in this Licensing Report. A summary of each TLAA identified for MPS3 in the LRA and the corresponding discussion for SPU is presented below.

Reactor Vessel Neutron Embrittlement

The evaluation of neutron fluence is summarized in the LRA. The staff reviewed the evaluation and determined that the calculation of the neutron fluence values, as projected through the period of extended operation for MPS3, is acceptable to use in the evaluation of the TLAAs for the USE, PTS, and P-T limit curves. The neutron fluence values were considered to be acceptable because MPS3 meets the guidelines of RG 1.190.

The staff reviewed the TLAA on USE, as summarized in the LRA, and determined that the RV beltline materials at MPS3 will continue to comply with the staff's USE requirements of 10 CFR 50, Appendix G, throughout the period of extended operation. The staff concluded that the TLAA for USE is in compliance with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(ii) and that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation as required by 10 CFR 54.21(c)(1).

Pressurized Thermal Shock - The staff reviewed the TLAA on PTS, as summarized in the LRA and determined that the RV beltline materials at MPS3 will continue to comply with the staff's requirements for PTS in 10 CFR 50.61 throughout the period of extended operation. The staff further concluded that the safety margins established and maintained during the current operating term could be maintained during the period of extended operation as required by 10 CFR 54.21(c)(1).

DNC has evaluated the impact of the SPU on the conclusions for PTS of the MPS3 beltline materials reached in the License Renewal Application. Updated neutron fluence projections accounting for the stretch power uprate are lower in magnitude than the projections of fluence used in the license renewal application for calculating PTS values of the beltline materials at 54 EFPY. The updated surface fluence as specified in Section 2.1.3 of this report was used in the current calculations of MPS3 beltline and extended beltline material PTS values at 54 EFPY and does not impact the USE results previously determined for the LRA using the higher neutron fluence.

Updated Pressure-Temperature Limits - DNC's review of P-T limits as discussed in the LRA covered the methodology and the calculations for the number of EFPY specified for the SPU and the plant life extension addressed in NUREG-1838. The LRA concluded that the P-T limits for MPS3 meet the definition in 10 CFR 54.4 for TLAAs, and assessed the P-T limits for the MPS3 against the acceptance criteria of 10 CFR 54.21(c)(1). The staff reviewed the assessment and concluded, pursuant to10 CFR 54.21(c)(1)(ii) and 10 CFR 54.21(c)(1)(iii), that the P-T limits can be generated for the period of extended operation in accordance with the technical specifications process. Millstone Unit 3 will calculate USE, RT_{PTS}, and P-T limits based on fluence values developed in accordance with RG 1.190 requirements, as amended or superseded by future regulatory guidance changes, through the period of extended operation. The staff will evaluate the P-T limit curves for the end of the extended operating term upon submittal. The staff's review at that time will ensure that the reactor coolant system for MPS3 is being operated in a manner that ensures the integrity of the reactor coolant system during the period of extended operation. The review will also ensure that the curves, when submitted, will satisfy the requirements of 10 CFR 54.21(c)(1)(ii) for the period of extended operation.

Metal Fatigue – The LRA for MPS3 included a TLAA for metal fatigue. Except for the pressurizer spray head, acceptable thermal and pressure transients, and operating cycles have been projected for ASME Section III, Class 1 components, through the period of extended operation. The pressurizer spray head assembly will be either replaced or inspected utilizing the best currently available (at the time of inspection) techniques for detecting cracking resulting from SCC. This commitment is identified in the FSAR Chapter 19, Table 19.6-1, License Renewal Commitments, Item 37.

The staff reviewed the metal fatigue TLAA and concluded that the actions and commitments satisfy the requirements of 10 CFR 54.21(c)(1). Section 2.2.6, NSSS Design Transients, of this report discusses the SPU impact on the fatigue program for the MPS3. The TLAAs on fatigue design will continue to be valid after the SPU by projecting that the original transient design cycles remain bounded for the 60-year operating period. The environmental effects on fatigue are discussed below.

Environmental Qualification – The staff has reviewed the information in the LRA regarding Environmental Qualification, and concluded that MPS3 has demonstrated the ability to manage the effects of aging during the period of extended operation for electrical components that meet the definition for TLAA as defined in 10 CFR 54.3. The SPU impact on Environmental Qualification of electrical equipment and the impact on component qualified life is discussed in Section 2.3.1, Environmental Qualification of Electrical Equipment, of this Licensing Report. DNC has evaluated the SPU impact on the conclusions reached in the MPS3 license renewal Safety Evaluation Report (SER) for the EEQ Program for electrical equipment. As stated in Section 2.3.3.1, the EEQ Program is within the scope of License Renewal. SPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation. Thus, SPU has no impact on the EEQ program.

Containment Liner Stress and Fatigue – The containment penetrations were evaluated in the LRA. The number of cycles used for the design of the containment liner plate penetrations was evaluated and found to be acceptable for the period of extended operation. The fatigue analysis of the containment liner plate and penetrations were projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). The staff found an acceptable assessment had been performed regarding the fatigue life of the liner plate pursuant to 10 CFR 54.21(c)(1)(ii). There is no change to the limiting conditions for containment and the liner; post-accident design limits continue to be met, therefore the conclusions of the TLAAs for containment liner stress and fatigue as a result of the SPU remain valid.

Crane Load Cycle Limit - The LRA identified Crane Load Cycle Limit as a TLAA and stated that each of the crane estimated cycle numbers is well below the upper Design Loading Cycle limit. The LRA identified the spent fuel crane as the most frequently used crane within the scope of license renewal. Considering all the uses, the spent fuel crane will most likely experience a total of 31,000 load cycles over a 60-year period. This number is well below the design load cycles of 100,000, and therefore is acceptable. A similar conclusion based on projected load cycles being well below the number of design load cycles was applied for the other cranes within the scope of license renewal. The staff found the conclusion reasonable and acceptable because a satisfactory basis for determining the projected number of lifts had been provided. In accordance with Section 2.5.7.2, the SPU will not have an effect on the number of design cycles experienced by the cranes, nor will the rated load change; therefore, the SPU has no impact on the Crane Load Cycle Limit TLAA discussion in the LRA.

Reactor Coolant Pump Flywheel - The fatigue-crack growth analysis for the RCP flywheels demonstrates that the postulated flaw identified in the analysis is not expected to grow in excess of the critical crack size, even when the flywheels are subjected to the change in the stress-intensity factor for the flywheels as associated with 6,000 RCP startup/shutdown cycles. As specified in Section 2.2.2.6, the NRC staff evaluation of RCP flywheel integrity for extended plant operation, as discussed and accepted in License Renewal SER Section 4.7B.2.2, remains valid for SPU conditions.

Thermal Aging Embrittlement - Thermal aging of cast austenitic stainless steel (CASS) material was evaluated for its effect on fracture toughness. The potential loss of fracture toughness for CASS material is managed by the inservice inspection program: systems, components and supports aging management program. For potentially susceptible CASS materials, either enhanced volumetric examinations or a unit or component specific flaw tolerance evaluation (considering reduced fracture toughness and unit specific geometry and stress information) will be used to demonstrate that the thermally embrittled material has adequate fracture toughness in accordance with NUREG-1801 Section XI.M12.3. This commitment is identified in the MPS 3 FSAR, Chapter 19, Table 19.6-1, License Renewal Commitments, Item 28. The staff found that the management of thermal aging embrittlement through inspection in accordance with 10 CFR 54.21(c)(1)(iii) was acceptable.

Section 2.1.6, Leak-Before-Break, presents the impact of the SPU on flaw tolerance analyses to evaluate the reduction in fracture toughness due to thermal aging of cast austenitic stainless steel through the extended period of operation. The analyses supporting the SPU demonstrate that large margins still exist for postulated flaw sizes against flaw instability; therefore, there is no change to the conclusions in the LRA of the TLAA for thermal aging embrittlement as a result of the SPU.

Environmentally Assisted Fatigue - The effects of the reactor water environment on the fatigue-sensitive locations were evaluated by the LRA. The evaluation indicated that the calculated usage factors might exceed 1.0 for four components: the surge line, the charging nozzle, the safety injection nozzle, and the RHR piping. The staff found that the Metal Fatigue of Reactor Coolant Pressure Boundary program provides additional assurance that the fatigue usage factor at these locations would not exceed the allowable limit of 1.0 during the period of extended operation. Consistent with 10 CFR 54.21(c)(1)(iii), those specific locations with a CUF that do exceed 1.0 will be managed by the Metal Fatigue of Reactor Coolant Pressure Boundary program. If the specific locations are not repaired, replaced, or successfully re-analyzed, a modified inspection program description will be submitted to the NRC for approval. This commitment is identified in the FSAR Chapter 19, Table 19.6-1, License Renewal Commitments, Item 27.

Additionally, in accordance with the FSAR Chapter 19, Table 19.6-1, License Renewal Commitments, Item 29, MPS3 committed to following industry efforts that will provide specific guidance for evaluating the environmental effects of fatigue on applicable locations, other than those identified in NUREG/CR-6260. MPS3 will implement the appropriate recommendations resulting from this guidance. Until these recommendations are available, MPS3 committed to using the pressurizer surge line nozzle as a leading indicator to address environmental effects of fatigue on pressurizer sub-components during the period of extended operation.

DNC has evaluated the impact of the SPU on the environmentally assisted fatigue evaluations performed in support of the LRA. The calculations used to support the LRA served as the basis for evaluating the impact of the SPU conditions on these conclusions. Calculations have been performed addressing the impact of the uprate conditions on the environmental fatigue evaluations of the NUREG/CR-6260 locations.

In accordance with Section 2.2.2.1, NSSS Piping, Components and Supports, DNC has evaluated the impact of the SPU on the fatigue evaluations performed in support of license renewal and has determined that the fatigue analyses performed to support license renewal bounds and remains valid for SPU conditions.

Leak Before Break (LBB) - Each of the LBB analyses associated with RCS components were evaluated for the period of extended operation. Thermal aging of CASS materials and fatigue crack growth calculations were determined to be time-based inputs as defined in 10 CFR 54.3 and required evaluation for the period of extended operation. The TLAA evaluations of metal fatigue were discussed in the LRA, and the staff's evaluation was provided in the SER. The metal fatigue TLAA evaluations (which envelop the components evaluated for LBB) concluded that design-basis limits would not be exceeded for ASME Class 1 components through the period of extended operation.

Corrosion of nickel-based alloys was also considered in the LRA. Cracking due to PWSCC of nickel-based alloys is managed by the *Inservice Inspection Program: Systems, Components, and Supports* Aging Management Program. MPS3 has committed to following the industry recommendations related to nickel-based alloys. This commitment is identified in the MPS 3 FSAR, Chapter 19, Table 19.6-1, License Renewal Commitments, Item 15. The staff found that an adequate demonstration was provided such that the TLAA for LBB evaluations remained valid or had been projected to the end of the period of extended operation.

DNC has evaluated the impact of the SPU on the conclusions reached in the MPS3 License Renewal Application for the impact on the LBB analysis and its assumptions. The evaluations performed for aging management concerning material fracture toughness remain valid for the SPU conditions.

2.14.3 Conclusion

The MPS3 Staff has reviewed the effect of SPU on the Renewed Plant Operating License. Based on this review MPS3 concludes that the effects of SPU renewed operating license have been accounted for and the aging effects of the SSCs within the scope of license renewal will be adequately managed through the extended period of operation.

ACRONYM LIST

Expression	Definition or Use
ΔRT_{NDT}	Irradiation induced shift in the Reference Nil Ductility Transition Temperature.
AAC	Alternate Alternating Current
AAGR	Annual Average Growth Rate
AC	Air Conditioning
ac	alternating current
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ADV	Atmospheric Dump Valve
AFW	Auxiliary Feedwater
AG	Air & Gas System
AHU	Air Handling Unit
AISC	American Institute of Steel Construction
ALARA	As Low As Reasonably Achievable
AMSAC	ATWS Mitigation System Actuation Circuitry
ANSI	American National Standards Institute
API	American Petroleum Institute
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transient Without SCRAM
BAST	Boric Acid Storage Tank
B&PV	Boiler and Pressure Vessel
B&WOG	Babcock and Wilcox Owners' Group
BMI	Bottom Mounted Instrument
BOP	Balance of Plant
B&W	Babcock and Wilcox
BRS	Boron Receiving System
BTP	Branch Technical Position
BWR	Boiling Water Reactor
CAP	Corrective Actions Program
CASS	Cast Austenitic Stainless Steel
CBI	Control Building Isolation

ACRONYM LIST

Expression	Definition or Use
CCP	Reactor Plant Component Cooling Water
CCWS	Component Cooling Water System
CDEP	Connecticut Department of Environmental Protection
CDF	Core Damage Frequency
CDL	Controlled Document Library
CE	Combustion Engineering, Inc.
CEA	Control Element Assembly
CEDM	Control Element Drive Mechanism
CEQ	Council on Environmental Quality
CFS	Condensate and Feedwater System
CFR	Code of Federal Regulations
CFs	Chemistry Factors
cfs	cubic feet per second
CHS	Chemical Volume Control System
CLB	Current Licensing Basis. The set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications. The CLB also includes the plant-specific design-basis information defined in 10 CFR 50.2, as documented in the most recent Final Safety Analysis Report (FSAR), as required by 10 CFR 50.71 and the licensee's commitments remaining in effect that have been made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports.
CL&P	Connecticut Light & Power
CLTP	Current Licensed Thermal Power
CMAA	Crane Manufacturers Association of America
CNS	Condensate
CNT	Containment Atmosphere Monitoring
CO_2	Carbon Dioxide
COLR	Core Operating Limits Report
COMS	Cold Overpressure Mitigation System

ACRONYM LIST

Expression	Definition or Use
COPS	Cold Overpressure Protection System
CR	Condition Report
CRAVS	Control Building Ventilation System
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
CRDS	Control Rod Drive System
CSPE	Chloro-Sulfonated Polyethylene
CUF	Cumulative Usage Factor
CVCS	Chemical and Volume Control System
CV_{USE}	Charpy Upper Self Energy
CWA	Clean Water Act
CWS	Circulating Water System
CZMA	Coastal Zone Management Act
DBA	Design Basis Accident
DBE	Design Basis Earthquake
DBLOCA	Design Basis Loss of Coolant Accident
DBR	Design Basis Review
DBS	Design Basis Summary
dc	Direct current
DCM	Design Control Manual
DCN	Design Change Notice
DCR	Design Change Record
DECLG	Double Ended Cold-Leg Guillotine
DER	Double Ended Rupture
DG	Draft Regulatory Guide
DNB	Departure from Nucleate Boiling
DNBR	Departure from Nucleate Boiling Ratio
DNC	Dominion Nuclear Connecticut
DOR	Division of Reactors
DPUC	Department of Public Utility Control
DWS	Domestic Water
DWST	Demineralized Water Storage Tank
ECCS	Emergency Core Cooling System

ACRONYM LIST

Expression	Definition or Use
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EDMS	Electronic Data Management System
EEQ	Electrical Equipment Qualification
EFPD	Effective Full Power Days
EFPH	Effective Full Power Hours
EFPY	Effective Full Power Year
EGA	EDG Starting Air
EGD	EDG Combustion Air Intake & Exhaust
EGF	EDG Fuel Oil
EGO	EDG Lube Oil
EGS	EDG Cooling Water
ELD	Electronic Licensing Documentation Database
EOL	End of Life
EPA	U.S. Environmental Protection Agency
EPDM	Ethylene Propylene Diene Monomer
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
EQ	Environmental Qualification (10 CFR 50.49)
EQB	Provides Environmental Qualification (EQ) Barrier and/or High Energy Line Break (HELB) Barrier
EQML	Equipment Qualification Master List
ER	Environmental Report (10 CFR 51), applicable to NEPA and environmental impacts.
ERC	Engineering Record Correspondence
ESF	Engineered Safety Features
ESFAS	Engineered Safety Features Activation System
ETA	Ethalolamine
Exemption	Plant-specific waiver granted pursuant to 10 CFR 50.12 and in effect that is based on a Time-Limited Aging Analysis.
FAC	Flow Accelerated Corrosion
FB	Provides a rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant.
FD	Provides for flow distribution.

ACRONYM LIST

Expression	Definition or Use
FCV	Flow Control Valve
FERC	Federal Energy Regulatory Commission
FES	Final Environmental Statement
FFs	Fluence Factors
FHA	Fire Hazards Analysis
FIV	Flow Induced Vibration
FLB	Feedwater Line Break
FLT	Provides filtration.
FP	Fire Protection (10 CFR 50.48)
FPER	Fire Protection Evaluation Report (MP3)
FrameMaker®	A desk-top publishing tool that is being used to produce the Millstone License Applications.
FSAR	Final Safety Analysis Report
GALL	Generic Aging Lessons Learned Report NUREG-1801
GDC	General Design Criterion
GEIS	Generic Environmental Impact Statement for License applications of Nuclear Plants
GL	Generic Letter issued by the NRC
GN2	Nitrogen
gpm	gallons per minute
GSI	Generic Safety Issue
GTR	Generic Technical Reports produced by the WOG, which document aging management reviews for major components and component groups.
HAC	High Alumina Cement
HEI	Heat Exchange Institute
HELB	High-Energy Line Break
HLSO	Hot Leg Switchover
HMWPE	High Molecular Weight Polyethylene
HPSI	High Pressure Safety Injection
HS	Provides a Heat Sink during SBO or a design basis accident.
HT	Provides for Heat Transfer.
HVAC	Heating, Ventilation, and Air Conditioning
HX	Heat Exchanger
IA	Instrument Air

ACRONYM LIST

Expression	Definition or Use
IASCC	Irradiation Assisted Stress Corrosion Cracking
ID	Inside Diameter
IEEE	Institute of Electrical & Electronics Engineers
IGSCC	Inter-Granular Stress-Corrosion Cracking
ILRT	Integrated Leak Rate Testing
IN	Information Notice
INPO	Institute of Nuclear Power Operations
ISFSI	Independent Spent Fuel Storage Installation
ISG	Interim Staff Guidance
ISI	In-Service Inspection
IWB	Subsection IWB of ASME Section XI Code
IWE	Subsection IWE of ASME Section XI Code
IWF	Subsection IWF of ASME Section XI code
IWL	Subsection IWL of ASME Section XI Code
JIS	Provides Jet Impingement Shielding for high-energy line breaks.
kV	kilovolt
LAR	License Amendment Request
LBB	Leak Before Break
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LHFF	LOCA Hydraulic Forcing Function
LIS	Long Island Sound
LIST	Licensing Information Search Tool (Old ELD)
LLRT	Local Leak Rate Testing
LOCA	Loss of Coolant Accident
LOOP	Loss Of Offsite Power
Long-lived component	A component that is not subject to replacement based on a qualified life or specified time period.
LPSI	Low Pressure Safety Injection
LR	Licensing Report
LSI	Provides Limited Structural Integrity
LTC	Limits Thermal Cycling
LTOP	Low Temperature Overpressure Protection

ACRONYM LIST

Expression	Definition or Use
LWRs	Light Water Reactors
MB	Provides a missile (internal or external) barrier.
MCC	480 V Motor Control Centers
MDF	Mechanical Design Flow
M&E	Mass and Energy
MEPL	Materials and Equipment Parts List
MFIV	Main Feedwater isolation Valve
MIC	Microbiologically Induced Corrosion
MIND	Management of Images and Nuclear Documents
MMOD	Minor Modification
MOS	Margin of Safety
MOV	Motor-Operated Valve
MPS	Millstone Power Station
MPS3	Millstone Power Station Unit 3
MR	Maintenance Rule
MSA	Metropolitan Statistical Area
MSIV	Main Steam Isolation Valve
MSL	Mean Seal Level
MSLB	Main Steam Line Break
MSR	Moister Separator Reheater
MSRC	Management Safety Review Committee
MSSV	Main Steam Safety Valves
MSVB	Main Steam Valve Building
MW	Megawatt
MWe	Megawatt-Electrical
MWt	Megawatt-Thermal
NACE	National Association of Corrosion Engineers
NADP	National Atmosphere Deposition Program
NCFM	Nuclear Component Fatigue Management
NCR	Non-Conformance Report
NDE	Non Destructive Examination
NDS	Nuclear Document Services
NEI	Nuclear Energy Institute

ACRONYM LIST

Expression	Definition or Use
NEPA	National Environmental Policy Act
NESC®	National Electrical Safety Code®
NESPTP	Nuclear Engineering Support Personnel Training Program
NFPA	National Fire Protection Association
NMA	Normal Maximum Average
NMFS	National Marine Fisheries Service
NNECO	Northeast Nuclear Energy Company
NOAA	National Oceanic and Atmospheric Administration
NO_x	Oxides of Nitrogen
NPDES	National Pollutant Discharge Elimination System
NPRDS	Nuclear Plant Reliability Data System
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NRS	Narrow Range Span
NS	Non-Safety-Related
NSPS	New Source Performance Standards
NSSS	Nuclear Steam Supply System
NU	Northeast Utilities
NUMARC	Nuclear Management and Resources Council
NUTIMS	Nuclear Training Information Management System
OBE	Operating Basis Earthquake
OD	Operability Determination
ODSCC	Outside Diameter Stress Corrosion Cracking
OE	Operating Experience
OPM	Office of Policy Management
Passive component	A component that performs an intended function without moving parts or without a change in configuration or properties.
Passive function	The specific intended function(s) performed by in-scope, passive components in support of system or structure intended functions.
PB	Provides pressure boundary
PCWG	Performance Capability Working Group
PDDS	Plant Design Data System
PGST	Primary Grade Storage Tank

ACRONYM LIST

Expression	Definition or Use
Plant commodity	Components such as cables, connectors, supports, conduit, and raceways, for which aging management reviews are performed on a plant basis. Plant commodities are not evaluated in system, structure, or major component AMRs.
PLAP	WOG Plant Life Assessment Program
PM	Preventative Maintenance
PMMS	Production Maintenance Management System
PNNL	Pacific Northwest National Laboratory
PORV	Pressurizer Power Operated Relief valve
ppb	Parts Per Billion
ppm	Parts Per Million
PRT	Pressurizer Relief Tank
P-T	Pressure Temperature
PTR	Project Topical Report
PTS	Pressurized Thermal Shock (10 CFR 50.61)
psi	Pounds Per Square Inch
psia	Pounds Per Square Inch Absolute
psid	Pounds Per Square Inch Differential
psig	Pounds Per Square Inch Gage
PVC	Polyvinyl Chloride
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
PZR	Pressurizer
QA	Quality Assurance
QAP	Quality Assurance Program
QAPD	Quality Assurance Program Description
QC	Quality Control
QDR	Qualification Document Review
QS	Quench Spray
RA	Regulatory Affairs
RC	Reactor Coolant
RCCA	Rod Control Cluster Assembly
RCD	Regulatory Commitment Database
RCL	Reactor Coolant Loop

ACRONYM LIST

Expression	Definition or Use
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RF	Restricts flow.
RG	Regulatory Guide
RHR	Residual Heat Removal
RI-ISI	Risk Informed – Inservice Inspection
rpm	Revolutions per Minute
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RS	Containment Recirculation
RSAC	Reload Safety Analysis Checklist
RSE	Reload Safety Evaluation
RSST	Reserve Station Service Transformer
RT	Radiography Testing
RTD	Resistance Temperature Detector
RT_{NDT}	Reference Nil Ductility Transition Temperature
RT_{PTS}	Reference Temperature for Pressurized Thermal Shock
RV	Reactor Vessel
RVI	Reactor Vessel Internals
RVHP	Reactor Vessel Head Penetration
RVID	Reactor Vessel Integrity Database
RVLIS	Reactor Vessel Level Instrument System
RVSS	Reactor Vessel Structural Support
RWST	Refueling Water Storage Tank
SA	Service Air
SAL	Safety Analysis Limit
SAMA	Severe Accident Mitigation Alternative
SAR	Safety Analysis Report
SBO	Station Blackout (10 CFR 50.63)
SC	Structures and Components
SCBA	Self Contained Breathing Apparatus
SCC	Stress-Corrosion Cracking

ACRONYM LIST

Expression	Definition or Use
SCR	Selective Catalytic Reduction
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SFRM	Safety Functional Requirements Manual
SG	Steam Generator
SGCS	Safety Grade Cold Shutdown
SGTP	Steam Generator Tube Plugging
Short-lived component	Components that are subject to replacement based on a qualified life or specified time period.
SHPO	State Historic Preservation Office
SI	Safety Injection
SIAS	Safety Injection Actuation Signal
SIS	Safety Injection System
SLCRS	Supplementary Leak Collection and Release
SMACNA	Sheet Metal and Air Conditioning Contractor National Association
SMITTR	Surveillance, Monitoring, Inspections, Testing, Trending, and Recordkeeping
SNS	Provides structural and/or functional support to equipment meeting LR Criterion 2 (non-safety affecting safety) and/or Criterion 3 (the five regulated events).
SO_2	Sulfur Dioxide
SO_x	Oxides of Sulfur
SP	Provides a Spray Pattern.
SPCS	Steam and Power Conversion systems
SPU	Stretch Power Uprate
SR	Safety-related
SRP	Standard Review Plan
SRS	Site Reporting System
SRSS	Square Roots Sum of the Squares
SS	Provides structural and/or functional support for in-scope equipment.
SSC	System, Structure, and Component
SSE	Safe Shutdown Earthquake
SSR	Provides structural and/or functional support for SR equipment.
SIPC	Structural Integrity Performance Criteria

ACRONYM LIST

Expression	Definition or Use
SWOL	Structural Weld Overlay
SWS	Service Water System
TE	Technical Evaluation
TGSCC	Trans-Granular Stress-Corrosion Cracking
TLAA	Time Limited Aging Analysis
TQR	Training Qualification Record
TRA	Test Report Assessment
TRM	Technical Requirements Manual
TS	Technical Specifications
TSCR	Technical Specification Change Request
TSP	Trisodium phosphate dodechaydrate
TSC	Total Suspended Particulates
USCB	U.S. Census Bureau
USE	Upper Shelf Energy
USFWS	U.S. Fish and Wildlife Service
UT	Ultrasonic Testing
VAC	Volts Alternating Current
VCT	Volume Control Tank
VETIP	Vendor Equipment Technical Information Program
VS	Provides for vortex suppression
VT	Visual Test
WINCDMS	Chemistry Data Management System
WOG	Westinghouse Owners' Group
WPCA	Water Pollution Control Authority
WRGM	Wide Range Gas Monitor
XLPE	Cross-linked polyethylene