February 9, 2006

Mr. James H. Lash
Vice President
FirstEnergy Nuclear Operating Company
Beaver Valley Power Station
P. O. Box 4
Shippingport, PA 15077

SUBJECT: BEAVER VALLEY POWER STATION, UNIT NO. 1 (BVPS-1) - ISSUANCE OF AMENDMENT RE: STEAM GENERATOR (SG) REPLACEMENT (TAC NO. MC6725)

Dear Mr. Lash:

The Commission has issued the enclosed Amendment No. 273 to Facility Operating License No. DPR-66 for BVPS-1. This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated April 13, 2005, as supplemented by letters dated August 26, October 28 and 31, November 18, and December 6 and 16, 2005.

The amendment revises the TSs to allow replacement of the BVPS-1 SGs. These changes include revising the fuel assembly-specific departure from nucleate boiling ratios and correlations, modifying the Overtemperature ΔT and Overpower ΔT equations, revising the SG water level low-low and high-high setpoints, revising the SG secondary side level in Modes 4 and 5, revising the SG TSs to reflect the replacement SGs and remove TS requirements that are no longer applicable to the new SGs, revising the required charging pump discharge pressure for reactor coolant pump seal injection flow, raising the accumulator pressure, and adding WCAP-14565-P-A (VIPRE) and WCAP-15025-P-A (WRB-2M) topical reports to the list of NRC-approved methodologies listed in TS 6.9.5. The amendment also approves an expanded selective alternate source term methodology implementation in accordance with Regulatory Guide 1.183, “Alternate Radiological Source Terms for Evaluating Design Basis Accidents at nuclear Power Reactors,” and approves use of the 1979 ANS Decay Heat + 2σ model for mass and energy releases for a main steam line break outside containment.

A copy of the related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Timothy G. Colburn, Senior Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-334

Enclosures: 1. Amendment No. 273 to DPR-66
2. Safety Evaluation

cc w/encls: See next page

A copy of the related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Timothy G. Colburn, Senior Project Manager
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2. Safety Evaluation

cc w/encls: See next page

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RidsAcrsAcnwMailCenter	RidsNrrDirsItsb	RidsNrrDraAadb
RidsNrr Dpr	RidsNrrLaSLittle	
RidsNrrDorlLpla	MBarillas	

Accession Number: ML060240146 *SE input provided. No substantive changes made.

OFFICE	LPLI-1/PM	LPLI-1/LA	PWSB/BC	CSGB/BC	AADB/BC(A)	ITSB/BC	OGC	LPLI-1/BC
NAME	TColburn	SLittle	JNakoski*	AHiser*	MKotzalas*	TBoyce	MBupp	RLaufer
DATE	1/30/06	1/30/06	12/20/05	06/23/05	12/16/05	2/08/06	02/08/06	2/09/06

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FIRSTENERGY NUCLEAR OPERATING COMPANY

FIRSTENERGY NUCLEAR GENERATION CORP.

DOCKET NO. 50-334

BEAVER VALLEY POWER STATION, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 273
License No. DPR-66

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by FirstEnergy Nuclear Operating Company, et al. (the licensee), dated April 13, 2005, as supplemented by letters dated August 26, October 28 and 31, November 18, and December 6 and 16, 2005, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (I) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-66 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 273, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented prior to entry into Mode 4 upon startup from refueling outage 1R17 which begins on or about February 10, 2006.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Richard J. Laufer, Chief
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: February 9, 2006

ATTACHMENT TO LICENSE AMENDMENT NO. 273

FACILITY OPERATING LICENSE NO. DPR-66

DOCKET NO. 50-334

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
2-1	2-1
3/4 3-3	3/4 3-3
3/4 3-5	3/4 3-5
3/4 3-5a	3/4 3-5a
3/4 3-5b	3/4 3-5b
------	3/4 3-5c
3/4 3-18	3/4 3-18
3/4 3-19a	3/4 3-19a
3/4 3-31	3/4 3-31
3/4 4-2d	3/4 4-2d
3/4 4-8	3/4 4-8
3/4 4-9	3/4 4-9
3/4 4-10	3/4 4-10
3/4 4-10a	3/4 4-10a
3/4 4-10b	3/4 4-10b
3/4 4-10c	3/4 4-10c
3/4 4-10d	3/4 4-10d
3/4 4-10e	3/4 4-10e
3/4 4-10f	------
3/4 4-10g	------
3/4 4-10h	------
3/4 4-10i	------
3/4 5-1	3/4 5-1
3/4 5-8	3/4 5-8
6-19	6-19

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 273 TO FACILITY OPERATING LICENSE NO. DPR-66

FIRSTENERGY NUCLEAR OPERATING COMPANY

FIRSTENERGY NUCLEAR GENERATION CORP.

BEAVER VALLEY POWER STATION, UNIT NO. 1 (BVPS-1)

DOCKET NO. 50-334

1.0 INTRODUCTION

By application dated April 13, 2005 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML051080573), as supplemented by letters dated August 26, October 28 and 31, November 18, and December 6 and 16, 2005 (ADAMS Accession Nos. ML052430345, ML053050300, ML053110142, ML053290139, ML053460239, and ML053560175), FirstEnergy Nuclear Operating Company (FENOC, the licensee), requested changes to the Technical Specifications (TSs) for BVPS-1. The supplements dated August 26, October 28 and 31, November 18, and December 6 and 16, 2005, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on June 21, 2005 (70 FR 35737).

The proposed changes would revise the TSs to allow replacement of the BVPS-1 steam generators (SGs) from the current Westinghouse Model 51 SGs to the new Westinghouse Model 54F SGs. These changes include revising the fuel assembly-specific departure from nucleate boiling ratios and correlations, modifying the Overtemperature ΔT and Overpower ΔT equations, revising the SG water level low-low and high-high setpoints, revising the SG secondary side level in Modes 4 and 5, revising the SG TSs to reflect the replacement SGs and remove TS requirements that are no longer applicable to the new SGs, revising the required charging pump discharge pressure for reactor coolant pump seal injection flow, raising the accumulator pressure, and adding WCAP-14565-P-A (VIPRE methodology) and WCAP-15025-P-A (WRB-2M correlation) to the list of Nuclear Regulatory Commission (NRC)-approved methodologies listed in TS 6.9.5. These WCAPs have previously been approved by the NRC. The amendment also would approve an expansion of the selective implementation of the alternate source term methodology in accordance with Regulatory Guide (RG) 1.183, "Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," and would approve use of the 1979 ANS Decay Heat + 2σ model for mass and energy releases for a main steam line break (MSLB) outside containment.

Additionally, the licensee proposes changes to TS 3.4.5, “Steam Generators.” Specifically, the proposed changes would revise the SG surveillance requirements (SRs) in support of the operation of BVPS-1 with replacement steam generators (RSGs). The changes to be made to the existing TS 3.4.5 are as follows:

- Addition of a note stating that inservice inspection is not required during the RSG outage.

- Removal of the alternate tube repair criteria requirements and their bases (voltage based repair criteria and W*) from the following TS Sections:

    - 4.4.5.2.b.5
    - 4.4.5.2.d and e

- Removal of SG tube sleeving (TIG, laser and Alloy 800 welded sleeving) requirements and their bases from the following TS Sections:

    - 4.4.5.2
    - 4.4.5.2.b.3 and 4
    - 4.4.5.4.a.1, 2, 3, and 4
    - 4.4.5.4.a.6.a, b, c, and d
    - 4.4.5.4.a.8

- Removal of references to all volatile water treatment (AVT) from TS Section 4.4.5.3.a.

- Removal of references to tube “repair” from TS Sections 4.4.5.4.a.5 and 6 and from Table 4.4-2.

Although the licensee performed its supporting technical analysis for this license amendment request (LAR) at a power level of 2900 MWt in support of its pending extended power uprate (EPU) license amendment request for BVPS-1 and 2, this LAR did not request, nor does this amendment authorize any increase in licensed power. This safety evaluation (SE) references some of the licensee’s submittals which provided information related to the licensee’s EPU technical supporting analyses as this LAR references those analyses as part of its technical supporting analyses.

Since the Westinghouse Model 54F SG is larger than the original Westinghouse-supplied SG (i.e., its tubes have a larger tube diameter, there are more tubes, and there is a greater tube surface area), it is expected that the proposed SG replacement will improve plant operations at normal operating power.

The NRC staff performed a review of the licensee’s LAR in accordance with the BVPS-1 licensing basis found in the Updated Final Safety Analysis Report (UFSAR) and NUREG-0800, “Standard review Plan” (Reference 7). The review focused on thermal-hydraulic design, systems evaluations, loss-of-coolant accident (LOCA) and non-LOCA transients and accident analyses, and the proposed TS changes associated with the replacement of SGs. Each of the review areas addressing the LOCA and non-LOCA transient and accident analyses was evaluated separately in their following respective SE sections. Each of these sections describes the applicable regulatory requirements and acceptance criteria, the licensee’s analyses or evaluations, and the NRC staff's conclusions. A detailed discussion on the computer codes and methodologies used in the RSG program can be found in Section 3.9.2 of this SE.

Additionally, the NRC staff reviewed the proposed adoption of the 1979 ANS Decay Heat +2 sigma model for mass and energy releases for an MSLB accident outside containment, and the proposed addition of the VIPRE Code with the WRB-2M correlation for use in the BVPS-1, UFSAR, Chapter 14 accidents re-analyses as part of the RSG program.

2.0 REGULATORY EVALUATION

BVPS-1 was designed and constructed to comply with the "General Design Criteria for Nuclear Power Plant Construction" published in July 1967 by the Atomic Energy Commission (AEC). Each criterion applicable to BVPS-1 is followed by a summary discussion of the design and procedures which are intended to meet the design objectives reflected in the criterion. Since the BVPS-1 construction permit was issued in June 1970, the compliance to the AEC General Design Criteria (GDC) of July, 1967 is addressed. Appendix IA of the UFSAR provides a discussion of the BVPS-1 degree of conformance to the AEC GDCs published in July 1971 as Appendix A to Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR). Modifications made to the plant satisfy the 1967 and 1971 GDCs as discussed in Section 1.3.2 and Appendix IA of the UFSAR, respectively.

The licensing acceptability of replacing the Model 51 operating SGs with Model 54F RSGs was evaluated by the licensee under the provisions of 10 CFR Section 50.59. The TS changes due to design differences between the Model 51 SGs and the Model 54F SGs were included in the licensee's April 13, 2005, LAR and are discussed in Section 3.11 of this SE. Items which must be included in the TS are defined in 10 CFR 50.36. SG tube SRs are included in the TSs for BVPS-1. Previously, license amendments were requested by the licensee and approved by the NRC as the SG tubes in the original BVPS-1 SGs degraded. These amendments modified the tube SRs consistent with the requirements of 10 CFR 50.90. A number of design and material changes will be incorporated with the installment of the RSGs which make some of the current requirements either inappropriate or unnecessary.

For the radiological dose consequence analysis, the NRC staff evaluated the radiological consequences of affected design-basis accidents (DBAs) for RSGs as proposed by the licensee against the dose criteria specified in 10 CFR 50.34(b)(2). These criteria are 25 rem total effective dose equivalent (TEDE) at the exclusion area boundary (EAB) for any 2-hour period following the onset of the postulated fission product release, 25 rem TEDE at the outer boundary of the low population zone (LPZ), and 5 rem TEDE in the control room (CR).

The radiological dose assessment portion of this SE addresses the impact of the proposed changes on previously analyzed DBA radiological consequences and the acceptability of the revised analysis results. The regulatory requirements for which the NRC staff based its acceptance are the accident dose criteria in 10 CFR. 50.67, as supplemented in Regulatory Position 4.4 of RG 1.183, Standard Review Plan (SRP), Section 15.0.1, and GDC19. The licensee proposed no deviation or departure from the guidance provided in RG 1.183. The

NRC staff's dose assessment evaluation is based upon the following regulatory codes, guides, and standards:

- 10 CFR Part 50.67, “Accident source term.”
- 10 CFR Part 50, Appendix A, "General Design Criterion for Nuclear Power Plants”: GDC 19, “Control room.”
- RG 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors.”
- RG 1.194, “Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants.”
- NUREG-0800, “Standard Review Plan,” Section 6.4, “Control Room Habitability Systems.”
- NUREG-0800, Section 15.6.2, “Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment.”
- SRP Section 2.3.4, “Short-Term Diffusion Estimates for Accidental Atmospheric Releases.”
- SRP Section 15.0.1, “Radiological Consequence Analyses Using Alternative Source Term.”

3.0 TECHNICAL EVALUATION

3.1 Nuclear Steam Supply System (NSSS) Parameters (LAR Section 2.1)

The NSSS design parameters provide the reactor coolant system (RCS) and secondary system conditions used in NSSS analyses and evaluations. The licensee provided a list of key plant parameters for the proposed RSGs in Table 2.1.1-2 of its LAR. Although the parameters are applicable to EPU conditions with the RSGs, this SE evaluates the replacement of the SGs at the current licensed reactor power level, not operation at EPU conditions. The major parameters in this table include reactor power level, NSSS power level, thermal design flow, reactor coolant pressure and temperatures, SG pressure, steam temperature, and steam flow rate. The licensee used a range of conditions for the vessel average temperature (T_{avg}), the SG tube plugging level, and a range of feedwater temperatures to generate the design operating parameters at EPU conditions that would bound the parameters at the current licensed reactor power level of 2689 MWt for the RSGs. Full-power normal operating vessel average temperature (T_{avg}) ranged from 566.2 EF to 580.0 EF, the SG tube plugging level varied from 0 percent to 22 percent, and feedwater temperature ranged between 400 EF and 455 EF. The current full-power normal operating vessel average temperature of 576.2 EF and feedwater temperature of 439.3 EF remain bounded by the new values. The SG tube plugging decreased to a value of 22 percent for the RSGs from the current value of 30 percent. The current NSSS power level of 2697 MWt, current fuel type, and current thermal design flow of 87,200 gpm/loop remain unchanged. The licensee used the new parameters in the safety analyses performed to support its proposed RSG program. The results of the licensee’s analyses determined acceptable margins to safety analysis limits and provided operational flexibility. The NRC staff reviewed these parameters and found them to adequately bound the current plant operating conditions with the proposed RSGs. Therefore, the NRC staff finds the NSSS design parameters acceptable.

3.2 NSSS Design Transients (LAR Section 2.2)

The licensee evaluated the current NSSS design transients that were based on conservative NSSS design parameters to determine any impact of the RSG conditions. The licensee compared the design parameters used in the existing design transients and those used for the RSG at EPU conditions. Even though the existing design parameters were bounded, a majority of the design transients were re-analyzed or evaluated based on the EPU design parameters using the NRC-approved LOFTRAN computer code to show the regulatory requirements continued to be met for the RSG at EPU conditions and the current NSSS design transients with the RSGs remain bounded by the EPU conditions. The NRC staff concluded the existing licensing basis design transients remain bounded by the analyses done at EPU conditions for the RSG program based on transients results found in Section 3.9 of this SE. The NRC staff concludes that the RSG program is acceptable for continued operation at the current licensed thermal rated power with the RSGs.

3.3 NSSSs (LAR Section 3)

The RCS and secondary system conditions that are assumed in accident analyses and SEs, are based upon the NSSS design parameters. The key design parameters include reactor power level, NSSS power level, thermal design flow, reactor coolant pressure and temperatures, SG pressure, steam temperature and steam flow rate. In this LAR, most of the changes in NSSS design parameters pertain to the SGs. They include an increased tube heat transfer area, increased tube flow area, lower steam pressure, and a longer narrow range level instrument span. A comparison of the RSGs with the current, original SGs (OSGs) is provided in the following table:

Comparison of Westinghouse Model 54F RSG to Model 51 OSG

	RSG	OSG	Change (percent)
Tube Material	Alloy 690TT	Alloy 600	
Tube Pitch Geometry	square	square	
Tube Pitch Geometry	square	square	
Tube Support Plate Type	quatrefoil	round	
Tube OD (in)	0.875	0.875	0.0
Tube Wall Thickness (in)	0.050	0.050	0.0
Tube Pitch (in)	1.225	1.281	-4.37
Number of Tubes	3592	3388	6.02

	RSG	OSG	Change (percent)
Tube Surface Area (sq ft)	54500	51500	5.82
Bundle Height (in)	417.5	417	.12
Tube Flow Area (sq ft)	11.767	10.956	7.40
Weight, Dry (lbs)	718,000	660,250	8.74
Secondary Side Circulation Ratio (Full Load)	3.3-3.6	5.0	-28
Steam Press (psig)	623-783	790	-21.13
Specified Maximum Carryover (percent)	0.10	0.25	-60.00
Narrow Range Span (in)	212	144	47

There is a 60 percent reduction in maximum carryover, a 21 percent decrease in steam pressure, and a 5.82 percent increase in heat transfer surface area. The larger narrow range span is due to the RSG. A larger range span will lead to a more stable indication of water level, and fewer low-low SG water level reactor trips during startup operations. Increase in secondary system cooling would be more readily seen by the RCS due to the improved primary-to-secondary heat transfer. Although these changes would benefit normal plant operations, this SE will focus on their effects on plant safety. The increase in heat transfer surface area would be expected to affect secondary-side induced transients, such as load rejection, loss of feedwater, and steam line rupture.

The licensee performed plant transients analyses and evaluations to verify that sufficient core cooling capability exists with the RSGs at EPU conditions, thus bounding current licensed power operation. The NSSS systems functional requirements and performance criteria were reviewed relative to the NSSS design parameters to show that each system remains capable of performing its design-basis function. The NSSS fluid systems analyses and evaluations were performed to consider the proposed NSSS design parameter changes associated with the RSGs at EPU conditions. The NSSS design parameter changes were verified to continue to meet the licensing basis acceptance criteria by re-analyzing and/or evaluating the transients using NRC-approved methodologies.

The NRC staff found the revised RCS and NSSS operating conditions associated with the RSG acceptable based on the results of the safety analyses addressed in Section 3.9 below.

3.4 Overpressure Protection (LAR Section 3.2.2)

Overpressure protection for the reactor coolant pressure boundary (RCPB) during power operation is provided by relief and safety valves and the reactor protection system. The licensee performed the analyses incorporating assumptions consistent with those specified in SRP Section 5.2.2 and WCAP-7769 (Reference 8). The licensee did not include an analysis for overpressure protection during power operation as part of the RSG submittal, but rather addressed it in the EPU licensing report enclosed with LAR No. 302 (Reference 9). In response to an NRC staff request for additional information (RAI), Question B.1 (response B.1 of its July 8, 2005, letter (Reference 2) and its December 2, 2005, letter (Reference 6)), the licensee provided information to demonstrate that the BVPS-1 safety valve design capacity continues to be sufficient to limit the pressure to less than 110 percent of the RCS pressure boundary design pressure during the most severe abnormal operational transient and during a reactor trip on the second safety-grade trip signal from the reactor protection system. The analyses showed there is sufficient margin available to account for uncertainties in the design and operation of the plant. Therefore, GDC 15 "Reactor coolant system design," continues to be met, 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 anticipated operational occurrences. The NRC staff found the LAR overpressure protection analyses bound the proposed BVPS-1 RSG operation at the current licensed rated thermal power (RTP). The NRC staff found the RSG program acceptable with respect to overpressure protection since no changes to the system that would reduce the margin in safety were necessary and the acceptance criteria continue to be met.

3.5 Low -Temperature Overpressure (LTOP) System/Cold Overpressure Mitigation System (COMS) (LAR Section 3.2.3)

The LTOP system, also known as the COMS, provides RCS pressure relief capability at relatively low-temperature operation (RCS temperature less than 350 EF). Two pressurizer power-operated relief valves (PORVs) are used to provide the automatic relief capability during the design-basis mass input and the design-basis heat input transients to automatically prevent the RCS from exceeding the pressure and temperature limits. The licensee performed an evaluation pursuant to 10 CFR 50.59 as part of the BVPS-1 RSG program. The licensee determined the COMS setpoints remain applicable for the RSG at the current licensed power level. The UFSAR, Chapter 14 accident analyses done at EPU conditions confirmed that overpressure protection is accomplished by the COMS and the pressurizer and main steam safety valves, and continues to bound current operation with the proposed RSGs. The NRC staff reviewed the licensee's COMS 10 CFR 50.59 evaluation (Reference 10) as part of this LAR review and found that the COMS 10 CFR 50.59 evaluation is acceptable since operation with the RSGs at the current licensed RTP requires no changes to the COMS and the system will continue to perform its design function.

3.6 Fuel Assemblies (LAR Section 6.0)

The fuel that is currently loaded in the BVPS-1 core is the Westinghouse 17×17 Vantage 5H fuel and Westinghouse 17×17 Robust Fuel Assembly (RFA) design, including the RFA-2 design. The transition to RFA fuel was initiated at the current power level of 2689 MWt. The Vantage 5H fuel design is mechanically and hydraulically compatible with the RFA fuel design. The fuel design is unchanged for the proposed RSG program. The non-LOCA transient analyses account for the fuel design features via fuel-related input assumptions such as fuel and cladding dimensions, cladding material, fuel temperatures, and core bypass flow. The NRC

staff found the fuel design remains acceptable, based on the results of the safety analyses addressed in Section 3.9 below.

3.7 Fuel Thermal Hydraulics Design (LAR Section 6.1)

The licensee proposed to use the rated thermal design procedure (RTDP) to perform statistical core thermal-hydraulic analyses, where applicable. Unlike the deterministic method, where the uncertainties of various plant and operating parameters are assumed simultaneously at their worst uncertainty limits in the safety analyses, the RTDP methodology statistically accounts for the system uncertainties in plant operating parameters, fabrication parameters, nuclear and thermal parameters, as well as the departure from nucleate boiling (DNB) correlation and computer codes uncertainties. The RTDP methodology establishes a design DNB ratio (DNBR) limit that statistically accounts for the effects of the key parameters on DNB. The RTDP methodology is documented in WCAP-11397-P-A (Reference 11). The DNB design criterion is that the probability that DNB will not occur on the most limiting rod is at least 95 percent at a 95 percent confidence level for any Condition I or II event. Since the parameter uncertainties are considered in determining the RTDP design limit, the plant safety analyses are performed using input parameters at their nominal values. The DNBR margin/penalty summary for transients using RTDP is given in Table 6.1-2 of this LAR. The standard thermal design procedure (STDP) was used for those analyses where RTDP is not applicable. The DNBR margin/penalty summary for transients using STDP is given in Table 6.1-3 of this LAR. In addition, the licensee used the WRB-1, W-3, and WRB-2 DNB correlations, consistent with the analysis of record. The licensee requested adoption of the WRB-2M correlation as part of this LAR. Further discussion addressing this request is found in Section 3.9.2 of this SE. The thermal hydraulic evaluation at EPU conditions for BVPS-1 showed that sufficient DNB margin is available using the different DNB correlations at EPU conditions so that the licensing basis acceptance criteria continue to be met. The NRC staff finds the licensee's application of RTDP methodology in these analyses to be acceptable since the licensee satisfied the conditions set on the RTDP methodology for application at BVPS-1. The NRC staff finds that the use of the WRB-2M correlation is acceptable on the fuel designs stated in Section 3.6 of this SE, since the re-analyzed accidents, as stated in Section 3.9, demonstrate that the DNB safety analysis limit (SAL) was not exceeded.

3.8 Control Rod Drive Mechanisms (CRDMs) (LAR Section 5.4)

The licensee evaluated the rupture of a CRDM housing pursuant to the 10 CFR 50.59 screening process (Reference 12) and determined there were no TS changes required for the BVPS-1 RSG LAR (Reference 1). The analysis performed at EPU conditions was evaluated for operation with RSGs at current power level for BVPS-1. The licensee concluded that operation of BVPS-1 at its current power level with RSGs is bounded by the EPU analyses. The rod ejection analysis confirmed that the current criteria in the BVPS-1 UFSAR continue to be met. Additionally, the existing analysis for the CRDMs meet the American Society for Mechanical Engineers *Boiler and Pressure Vessel Code* (ASME Code) pressure requirements. The NRC staff agrees that operation at the current licensed power level with the RSGs remains bounded by the EPU analyses and that no changes are required to the CRDMs that would affect the system's design function. Therefore, the NRC staff finds that the licensee's 10 CFR 50.59 evaluation for CRDMs is acceptable with respect to the proposed RSG program.

3.9 Transient and Accident Analyses (LAR Section 5)

The licensee re-analyzed the UFSAR, Chapter 14, LOCA and non-LOCA transients and accident analyses in support of the BVPS-1 RSG program at a power level that bounds the current licensed power level of 2689 MWt. These analyses were performed at a rated core power of 2900 MWt using EPU plant parameter values. Initial condition uncertainties for pressurizer pressure control, RCS T_{avg} control, reactor power, RCS total flow, SG water level control, and pressurizer water level control were affected by the EPU conditions modeled in the BVPS-1 safety analyses. The initial condition uncertainties were recalculated for the EPU conditions for use in the BVPS-1 analyses and/or evaluations that were performed to assess the acceptability of the safety analyses for the RSG program. Table 5.1-1A of Reference 1 lists the initial condition uncertainties. These uncertainty calculations were performed at EPU conditions based on the plant-specific instrumentation and plant calibration and calorimetric procedures. The NRC staff reviewed the licensee's transient and accident analyses for applicability to the RSG program to verify that the acceptance criteria were met under these conditions and are bounding for the RSG program. The NRC staff's review of the LOCA and non-LOCA transients and accidents is discussed below.

3.9.1 LOCA Evaluation (LAR Section 5.2)

GDC 35, "Emergency core cooling," requires each pressurized-water reactor (PWR) and boiling-water reactor (BWR) to be equipped with an emergency core cooling system (ECCS) that refills the vessel in a timely manner to satisfy the requirements of the regulations for ECCS given in 10 CFR 50.46 and Appendix K to 10 CFR Part 50. The 10 CFR 50.46 acceptance criteria for the ECCS include limits on peak cladding temperature (PCT), maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long-term cooling. 10 CFR 50.46 gives reporting requirements for the evaluation model and changes to the model and the model inputs. The evaluation model must be plant specific and reviewed and approved by the NRC. There are two distinct models for large-break LOCA (LBLOCA) and small-break LOCA (SBLOCA). There is an annual reporting requirement to assure that the plant-specific analysis of record (AOR) represents the current plant configuration. Code errors and input model changes to the AOR are quantified as a change in PCT. The absolute values of these changes are summed. When the summed amount of change becomes equal to or exceeds 50 EF, a re-analysis must be performed and reviewed and approved by the NRC.

3.9.1.1 LBLOCA

The limiting LBLOCA in a PWR is a break in the cold leg of the RCS. During the reflood phase, ECCS water boils into steam after coming in contact with the hot core. For the steam to escape the core it has to travel through hot leg, into the SG tubes, through the reactor coolant pump (RCP), and then out the break in the cold leg. Plugging of SG tubes increases flow resistance in the loop. Increased resistance in the loop tends to limit venting of steam from above the core during a LBLOCA and thereby suppresses the reflood rate in the core. This is referred to as steam binding.

Replacing the BVPS-1 SGs with new ones having few or no plugged tubes will decrease post-LOCA steam binding in the loops and result in increased venting of steam from the plenum above the core. This will produce a faster core reflood rate with resulting less severe event consequences (PCT, fuel oxidation, and core-wide hydrogen generation). These results and the BVPS-1 ECCS design assure that the replacement of the BVPS-1 SGs will result in increased ECCS effectiveness such that the plant will continue to maintain a coolable geometry and long-term cooling. Based on this, the NRC staff agrees with the licensee's conclusion that the current LBLOCA AORs performed for BVPS-1 with the OSGs bound the operation of

BVPS-1 with RSGs.

3.9.1.2 10 CFR 50.46 Reporting Requirements

In the licensee's February 11, 2005, RAI response (Reference 13) related to its LAR for approval to use the Westinghouse best-estimate LOCA (BELOCA) methodology, the licensee stated that the last LBLOCA analyses that had been reviewed and approved by the NRC was in 1993 for BVPS-1. The sum of the absolute values of all accumulated PCT changes since then exceeds 50 °F. The proposed schedule for re-analysis pursuant to 10 CFR 50.46, is currently under review by the NRC. As a result of the accident analyses supporting the BVPS-1 and 2 LAR for conversion of the containments from subatmospheric to atmospheric operating conditions, there was a 91 °F decrease in PCT in its LBLOCA analyses. The RSGs will also result in a reduction of the calculated PCT. The licensee originally submitted Reference 1 as part of the EPU LAR. The licensee proposes to adopt the BELOCA large-break LOCA analyses as the new AOR. The BELOCA analyses were submitted to the NRC by letter dated October 4, 2004 (Reference 14), and were approved on February 6, 2006. Since the effect of the RSG will increase the ECCS effectiveness in response to a LBLOCA, and the current LBLOCA AOR performed considering the existing Model 51 OSGs bounds conditions associated with the RSGs, approval of the BVPS-1 RSG program is acceptable. It is not dependent upon the NRC staff completion of its review of the revised LBLOCA analyses associated with the BVPS-1 and 2 EPU LAR.

3.9.1.3 SBLOCA

The BVPS-1 SBLOCA analyses are performed using the Westinghouse NOTRUMP evaluation methodology. This methodology does not use containment back-pressure in the model since the break flow is at critical flow conditions for most of the transient. The present SBLOCA analysis results continue to bound analyses incorporating modeling of the RSG because of the resulting enhancement of core and upper plenum venting (particularly for larger small breaks), as discussed above. The availability of more steam generator tubes would expedite cooldown, and in many cases (particularly smaller small breaks) enhance natural circulation. For these many cases, the plant could be depressurized, cooled, and borated using the ECCS in a manner similar to a normal shutdown. In all cases, improved ECCS performance can be expected. In particular, for small breaks the larger primary tube inventory would delay core uncovery and decrease the maximum depth of uncovery for all breaks. The larger SGs, in effect, reduce PCT for small breaks. Therefore, the NRC staff finds that the BVPS-1 RSGs are acceptable with respect to the SBLOCA analyses. Since the SG replacement proposed by the licensee does not adversely affect the current SBLOCA AOR, the approval of this LAR is not dependent upon the results of the SBLOCA re-analysis submitted in support of the BVPS-1 and 2 EPU LAR.

3.9.1.4 Post-LOCA Long-Term Cooling and Boron Precipitation (LAR Section 5.2.4)

The RSG does not introduce an increased loop resistance or pressure drop from the core exit to the discharge in the pump coolant discharge leg. Therefore, analyses of the mixing volume and the resultant boric acid precipitation timing and switch to simultaneous injection will remain unchanged. While post-LOCA long-term cooling performance, including precipitation timing following all LOCAs, will not change adversely as a result of SG replacement, approval of this change to replace SGs does not constitute approval of the analysis methods and results to compute the boric acid precipitation timing. Approval of this change, therefore, does not resolve the NRC staff's ongoing generic issues pertinent to the methods and analyses employed by the vendors to assess post-LOCA long-term cooling and boric acid precipitation following LB and SBLOCAs.

3.9.2 Non-LOCA Transients and Accidents (LAR Section 5.3)

The licensee re-analyzed and/or evaluated the BVPS-1 UFSAR, Chapter 14, non-LOCA events using NRC-approved computer codes and methodologies. Tables 1.0, 2.1.1, 5.3.20, and 6.1.3, of Reference 1 provide non-LOCA computer codes, plant initial conditions and assumptions, and results of the re-analyses for the proposed BVPS-1 RSG program.

The licensee requested adoption at BVPS-1 of the VIPRE computer code as described in WCAP-14565-P-A (Reference 15), as part of Reference 1 for DNB analyses of accidents and transients such as the steam line break, rod withdrawal from subcritical or at power, loss of forced reactor coolant flow, locked RCP rotor or shaft break, dropped control rod, startup of an inactive RCP, and a feedwater malfunction. The VIPRE code is a three-dimensional subchannel code that was developed to account for hydraulic and nuclear effects on the enthalpy rise in the core and hot channels. The VIPRE code is used with the applicable DNB correlations to determine DNBR distributions along the hot channels of the reactor core under all expected operating conditions. Inputs to VIPRE that describe the radial and axial power shapes, engineering hot channel factors for enthalpy rise and heat flux are specific to the reactor core being analyzed. These BVPS-1 inputs are noted throughout Section 5.3 of Reference 1. A 5-percent reduction factor to the flow entering the hot channel was applied when using the VIPRE code. The NRC staff reviewed the licensee's submittals and determined the licensee met the conditions stated in the NRC's SE dated January 19, 1999 (Reference 16) approving the VIPRE code. Therefore, the NRC staff finds it acceptable for the licensee to use VIPRE at BVPS-1 for the applicable analyses described in WCAP-14565-P-A.

The licensee also requested adoption of WCAP-15025-P-A, WRB-2M correlation (Reference 17) to predict critical heat flux at BVPS-1. This change is being made to support the enhanced fuel performance. The WRB-1 correlation is applicable for both V5H and RFA fuel assemblies, but is conservative for the RFA assemblies. The WRB-2M correlation has a DNBR limit of 1.14 in comparison to the WRB-1 and WRB-2 limit of 1.17. The licensee addressed each of the conditions required to be met by the NRC's SE dated December 1, 1998 (Reference 18) approving the WRB-2M correlation. In response to an NRC staff RAI on meeting Condition 4 of the WRB-2M SER, the licensee provided in response No. 3 of its November 18, 2005, letter (Reference 4), a table demonstrating that each of the conditions are met for the fuel assemblies referenced. The NRC staff finds it acceptable for BVPS-1 to use the WRB-2M correlation to predict critical heat flux since all the conditions and limitations specified in the NRC's SER and WCAP-15025-P-A are met.

The licensee used the LOFTRAN computer code for the majority of the events to simulate the transient response characteristics of BVPS-1, consistent with the AOR licensing basis. The licensee also used VIPRE for reactor core subchannel thermal-hydraulic calculations as discussed in WCAP-14565-P-A, and the WRB-2M correlation as discussed in

WCAP-15025-P-A for DNBR calculations. In all applications, the codes were used within their specified conditions and limitations.

3.9.2.1 Uncontrolled Rod Cluster Control Assembly (RCCA) Withdrawal from a Subcritical Condition (LAR Section 5.3.2)

The uncontrolled RCCA withdrawal from subcritical or low-power startup condition is an American National Standard (ANS) Condition II (Reference 19) event that is characterized by the insertion of positive reactivity to the reactor core due to the inadvertent withdrawal of an RCCA bank while the plant is in a subcritical or low-power startup condition. As such, it is not sensitive to secondary-side conditions or SG performance parameters. The analysis for this event does not model SGs. The licensee re-analyzed this event for the BVPS-1 RSG LAR at EPU conditions using the TWINKLE, FACTRAN, and VIPRE computer codes. The results of the analysis showed that the minimum DNBR for the transient remains above the safety analysis limit value, and peak fuel clad temperature is not exceeded at the NSSS power of 2910 MWt.

The NRC staff has reviewed the licensee's analysis of the uncontrolled RCCA withdrawal from a subcritical condition and concludes that the licensee's analysis was performed using acceptable analytical models. The NRC staff also concludes, based on its review of this analysis, that the plant will continue to meet the regulatory requirements following implementation of the proposed RSG program at the current licensed RTP. Therefore, the NRC staff finds that the proposed RSG program is acceptable with respect to the uncontrolled RCCA withdrawal from a subcritical condition event.

3.9.2.2 Uncontrolled RCCA Withdrawal at Power (LAR Section 5.3.3)

Unlike the uncontrolled RCCA withdrawal from subcritical or low-power startup condition, the uncontrolled RCCA withdrawal at power, also an ANS Condition II event, is affected by the secondary system, since the secondary system is relied upon to remove heat from the primary system while the plant is at power. If the RCCA bank withdrawal event is not terminated by manual or automatic action, the power mismatch and resultant temperature rise could cause DNB and/or fuel centerline melt, and RCS pressure could increase to a level that could challenge the integrity of the RCS pressure boundary or the main steam system (MSS) pressure boundary. The acceptance criteria are based on not exceeding critical heat flux and that pressures in the RCS and MSS be maintained below 110 percent of the design pressures. Specific review criteria are found in the SRP, Section 15.4.2.

The licensee used LOFTRAN to analyze the uncontrolled RCCA withdrawal at power event, consistent with the AOR. The core thermal limits were recalculated for this project using the VIPRE computer code. The uncontrolled RCCA withdrawal at power event analysis credits reactor trips from only the power-range nuclear instrument (NI) high neutron flux and overtemperature Δtemperature (OTΔT) trip signals. Many cases were considered at initial power levels of 10, 60, and 100 percent of RTP, with minimum reactivity feedback (i.e., with a moderator temperature coefficient (MTC) of reactivity of 0 pcm/EF at full power, and +5 pcm/EF at 60 percent and 10 percent power), and maximum reactivity feedback (i.e., a conservatively negative MTC), and with a range of reactivity insertion rates, the maximum positive reactivity insertion rate being greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined differential rod worth at a conservative speed (77 steps/minute). The range of cases selected was consistent with the SRP, Section 15.4.2. The licensee determined that the proposed BVPS-1 RSG program did not impact the core limits. For the slower reactivity insertion rates, the OTΔT trip signal was generated before the power-range NI high neutron flux trip signal. For the faster reactivity insertion rates, the power-range NI high neutron flux trip signal occurred first. Both cases analyzed show the minimum DNBR was greater than the SAL value of 1.55. For the BVPS-1 uncontrolled RCCA at power event, the analysis results indicated that the minimum DNBR, 1.57, occurs during the case that is analyzed at 60 percent initial power with minimum reactivity feedback and a constant reactivity insertion rate.

In response to an NRC staff's RAI regarding overpressurization, the licensee stated in RAI response H.3 of Reference 2 and RAI response 7 of Reference 4, that Westinghouse performed generic analyses showing adequate protection would be provided through the use of the high neutron flux and high pressurizer pressure reactor trip functions to prevent overpressurization for this event. An NRC staff review of the key input parameters made in the generic analyses using the approved LOFTRAN computer code demonstrated the analyses were applicable and bounding for the BVPS Unit 1 RSG. The table provided in Reference 4, RAI response 7, shows some of the different parameters by which BVPS-1 remains bounded.

The NRC staff reviewed the licensee's analyses of the uncontrolled RCCA withdrawal at power event and concluded that the licensee's analyses were performed using acceptable analytical models. The NRC staff also concluded that the plant will continue to meet the regulatory requirements in the AOR following implementation of the proposed RSG program. Therefore, the NRC staff finds the proposed RSG program acceptable with respect to the uncontrolled RCCA withdrawal at power event.

3.9.2.3 RCCA Misalignment (LAR Section 5.3.4)

The RCCA misoperation events are ANS Condition II events that include incidents such as:

- Statically misaligned full-length RCCA
- One or more dropped full-length RCCAs
- A dropped full-length RCCA bank

These are transients that are driven by core reactivity and nuclear flux responses to changes in rod positions and are not sensitive to secondary-side conditions. These events are analyzed generically in accordance with WCAP-11394-P-A modeling a 3-loop reactor design (Reference 20). The generic dropped RCCA statepoints are evaluated each cycle as part of the reload SE process in order to demonstrate that the applicable DNB design basis is satisfied. In RAI response I.1 of Reference 2, the licensee provided an explanation on how the generic statepoints are applicable and remain valid to BVPS-1 for the RSG program. The DNBR safety analysis limit is not exceeded and the acceptance criteria continue to be met.

The NRC staff agrees with the licensee's discussion on the applicability and validity of the generic statepoints for the BVPS-1 RSG program. The licensee's approach for the RCCA misoperation events demonstrates the applicability of the NRC-approved WCAP-11394-P-A for BVPS-1. Therefore, the NRC staff agrees that the licensing basis acceptance criteria continue to be met and finds that the RCCA misalignment evaluation is acceptable.

3.9.2.4 Chemical and Volume Control System (CVCS) Malfunction that Results in a Decrease in the Boron Concentration in the RCS (LAR Section 5.3.5)

Reactivity can be added to the core by feeding primary 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. 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. This event is classified as an ANS Condition II event that requires that the critical heat flux is not exceeded, pressure in the RCS be maintained below the 110 percent design pressure and there is enough time available for operator action that will prevent loss of shutdown margin (SDM).

Analysis of this event involved a calculation of how long it would take for a constant dilution rate to loose available SDM. The key parameters of interest were the dilution flow, the active RCS volume, the initial boron concentration and the critical boron concentration. The licensee provided the parameters for each mode in Table A.1-9 of Reference 2. An active RCS volume of 6964 ft^3 was assumed for the boron dilution during Mode 3. An active RCS volume of 7593 ft^3 was assumed during Modes 1 and 2. The RSGs would affect this event analysis since they are part of the active RCS mixing volume. Since the RSGs are larger than the OSGs, the mixing volume would also be larger. Given the same dilution flow, and boron concentrations, the time for a boron dilution event to maintain acceptable SDM is expected to be longer.

The licensee re-analyzed this event using the RSG volume, current dilution flow, and current critical boron concentration. The licensee evaluated the CVCS malfunctioning in Modes 1, 2, and 3. The licensee stated there are administrative controls in place during Modes 4, 5, and 6 that isolate the primary water system isolation valves from the CVCS, located in TS 3.1.2.9. Unborated water cannot be injected into the RCS inadvertently, making an unplanned boron dilution during these Modes improbable. The licensee provided its response in Enclosure 3 of Reference 6, to an NRC staff RAI regarding inclusion of operator notification to the loss of SDM time calculation during Mode 3. The BVPS-1 licensing basis is in accordance with RG 1.70, Revision 0 (Reference 21), and predates the SRP requirements for including the time for operator notification during a boron dilution event in the total response time during Mode 3. The acceptance criteria BVPS-1 is licensed to state there must be at least 15 minutes available before loss of SDM in Modes 1, 2, and 3. The licensee demonstrated in its transient analyses that there are at least 15 minutes available in Mode 3 for the operators to take corrective action before SDM is lost. The licensee implicitly accounted for operator notification from initiation of event to loss of SDM in its calculations during Mode 1 (automatic rod control) and during Mode 2 and determined there were at least 30 minutes available during these modes for operators to take corrective action before loss of SDM. The licensee explicitly accounts for operator notification in Mode 1 (manual rod control) and determined there are at least 30 minutes available for operators to take corrective action before loss of SDM.

The NRC staff concludes that the acceptance criteria continue to be met for the boron dilution transient since there is no loss of shutdown margin, the critical heat flux is not exceeded and pressure in the RCS remains below the 110 percent design pressure. Therefore, the NRC staff finds the evaluation acceptable for the RSG program.

3.9.2.5 Loss of External Electrical Load/Turbine Trip (LAR Section 5.3.6)

A major loss of load can result from either a loss of external electrical load or from a turbine trip from full power without a direct reactor trip. These events result in a sudden reduction in steam flow. The loss of heat sink leads to pressurization of the RCS and MSS. The ANS Condition II acceptance criteria applicable to this event are that critical heat flux is not exceeded, pressure in the RCS and MSS are maintained below 110 percent of the design pressures values, and an incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently. Specific review criteria are found in the SRP, Section 15.2.1-5.

The licensee analyzed two cases for a complete loss of load from full power at EPU conditions with the RSG: 1) minimum reactivity feedback with pressure control; and 2) minimum reactivity feedback without pressure control. The primary concern for the case analyzed with pressure control was the minimum DNBR. The primary concern for the case analyzed without pressure control was maintaining RCS pressure below 110 percent of the design pressure. The licensee performed the analyses using the LOFTRAN computer code, consistent with the AOR, to determine the plant transient conditions following a complete loss of load for both conditions. The case with pressure control was analyzed using the RTDP at a power level of 2910 MWt. For the case with pressure control, the reactor tripped on the OTΔT signal. The minimum DNBR obtained was 2.23, above the SAL of 1.55. There was no concern with the event escalating to an ANS Condition III SBLOCA, since the peak water volume remained below the total pressurizer volume demonstrating no water solid condition occurred.

The case without pressure control was analyzed using the STDP. The reactor tripped on high pressurizer pressure. The licensee's analysis assumed operation of pressurizer safety valves (PSVs) and MSS safety valves to maintain pressure below the 110 percent design pressure. The peak primary pressure reached was 2744.6 psia, below the design limit of 2748.5 psia and the peak secondary pressure reached was 1187.7 psia, below the design limit of 1208.5 psia. The peak pressurizer water volume remained below the total pressurizer volume demonstrating no water solid condition occurred.

The NRC staff reviewed the licensee's analyses of the loss of external electric load and concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff finds that the licensee demonstrated that the minimum DNBR will remain above the SAL and pressure in the RCS and MSS will remain below 110 percent of the design pressure values for the proposed RSG program. The NRC staff concludes that the BVPS-1 loss of external electric load/ turbine trip analyses at EPU conditions are bounding for the proposed RSG program and BVPS-1 will continue to meet applicable regulatory requirements following implementation of the RSG. Therefore, the NRC staff finds that the proposed RSG program is acceptable with respect to the loss of external electrical load event.

3.9.2.6 Loss of Normal Feedwater Flow (LAR Section 5.3.7)

A loss of normal feedwater (LONF) event, an ANS Condition II event, results in a reduction in capability of the secondary system to remove heat from the primary side. The loss of heat sink requires the reactor trip and an alternate supply of feedwater be supplied to the SGs. Following reactor trip, it is necessary to remove residual heat and RCP heat to prevent RCS pressurization and loss of primary system water inventory through the pressurizer relief and safety valves. If enough RCS inventory is lost, then core damage could occur. Since the reactor is tripped before the SG heat transfer capability is reduced, the primary system conditions never approach those that would result in a violation of the limit DNBR. The reactor protection system (RPS) provides the protection against a LONF event via a reactor trip on SG low-low water level in one or more SGs. The auxiliary feedwater (AFW) system starts automatically on SG low-low water level, following a safety injection (SI) signal, on loss-of-offsite power (LOOP), or on trip of both main feedwater pumps. The LONF analysis demonstrates that following a LONF, the AFW system is capable of removing 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. The acceptance criteria are based on the critical heat flux not being exceeded and pressure in the RCS and MSS are maintained below the 110 percent design pressure. Specific review criteria are found in the SRP, Section 15.2.7.

The LONF transient was analyzed using the LOFTRAN computer code, consistent with the AOR, with the RSG at EPU conditions. A RCP heat of 15 MWt was included in the analysis to account for the heat released by the pumps. Reactor trip occuring on SG low-low water level was assumed to be set at 5 percent of narrow range span (NRS). A conservative core residual heat generation was assumed based on the ANS 5.1-1979 Decay Heat +2 sigma model for uncertainties (Reference 22). The licensee analyzed the SG tube plugging conditions of both 0 percent and 22 percent. Sixty seconds after the SG low-low water level setpoint was reached, AFW system flow from both motor-driven AFW pumps was initiated with flow split equally among the three SGs. The worst single failure modeled was the loss of the turbine-driven AFW pump. The pressurizer sprays and PORVs were assumed operable to maximize the pressurizer water volume. If these control systems did not operate, the pressurizer safety valves would prevent the RCS pressure from exceeding the RCS design pressure limit during the transient.

The licensee provided the justification for determining the LONF was bounded by the LOL transient in response to an NRC staff RAI in response L.1 of Reference 2. Both of these transients represent a reduction in the heat removal capability of the secondary system. For the LOL transient, the turbine trip was the initiating event, and the power mismatch between the primary and secondary side was much more severe. This resulted in a more severe RCS heatup in the LOL transient than for the LONF transient. Therefore, the LOL transient will be more severe with respect to the minimum DNBR criterion. The minimum DNBR for the LOL transient was 2.23, above the SAL of 1.55. The pressurizer did not become water-solid during this transient since the peak pressurizer volume reached was 1384 ft^3, below the design limit of 1458 ft^3. The AFW system capacity is sufficient to dissipate core residual heat, stored energy, and RCP heat such that reactor coolant water would not relieve through the pressurizer relief or safety valves.

The NRC staff reviewed the licensee's analysis for the LONF transient and concludes that the analysis was performed using acceptable analytical models. The NRC staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed RSG program. The NRC staff concludes that the licensee's analysis at the EPU conditions bound current licensed power operation of BVPS-1 with the proposed RSGs.

Therefore, the NRC staff finds that the proposed RSG program is acceptable with respect to the LONF event.

3.9.2.7 Loss of Non-Emergency AC Power to the Station Auxiliaries (LAR Section 5.3.8)

The loss of non-emergency AC power, an ANS Condition II event, cuts off all power to the station auxiliaries and trips all RCPs. The reactor and turbine trip, the RCPs coastdown, reactor coolant pressure and temperature rise and heat removal by the secondary system decreases. Following the RCP trip, the reactor coolant flow necessary to remove residual heat is provided by natural circulation, which is driven by the secondary system and the AFW system. The RPS generates the actuation signals needed to mitigate the transient. The ANS Condition II acceptance criteria are based on the critical heat flux not being exceeded and pressure in the RCS and MSS being maintained below 110 percent of the design pressures. Specific review criteria are found in the SRP, Section 15.2.6.

The licensee used the LOFTRAN computer code to analyze this event, consistent with the AOR, with the RSG at EPU conditions. From its analysis, the licensee concluded that for a loss of AC (LOAC) power to the station auxiliaries, the plant response was almost identical to the complete loss of reactor coolant flow event. After the reactor trip, the AFW system removes decay heat and this portion of the transient is similar to the LONF event. The LOFTRAN code results showed that natural circulation and the available AFW flow were sufficient to provide adequate core decay heat removal following a reactor trip and RCP coastdown. The pressurizer did not reach a water-solid condition and the pressurizer relief and safety valves do not discharge any water. The peak pressurizer volume reached for this event was 1224 ft^3, remaining below the safety limit of 1458 ft^3. The RCS and MSS pressures remain below the applicable design limits throughout the transient. The licensee stated that this event was bounded by the complete loss of reactor coolant flow event. The first few seconds of the transient would be almost identical to the complete loss of reactor coolant flow event, during which the reactor trips and prevents the DNBR from falling below the DNBR safety analysis limit. However, the RCS flow coastdown was the initiating fault in the complete loss of flow event. The reactor trip occurs after the flow has already been degraded. In the loss of non-emergency AC power event, the flow coastdown occurred after reactor trip.

The NRC staff reviewed the licensee’s analysis of the LOAC power to plant auxiliaries and concludes that the licensee’s analysis was performed using acceptable analytical models. The NRC staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed RSG program. The NRC staff concludes that the analysis performed with the RSG at EPU conditions bounds current licensed power operation with the RSGs. Therefore, the NRC staff finds that the proposed RSG program is acceptable with respect to the LOAC power to the plant auxiliaries.

3.9.2.8 Excessive Heat Removal Due to Feedwater System Malfunctions (LAR Section 5.3.9)

A change in SG feedwater conditions that results in an increase in feedwater flow or a decrease in feedwater temperature could result in excessive heat removal from the RCS. Such changes in feedwater flow or feedwater temperature are a result of a failure of a feedwater control valve or feedwater bypass valve, failure in the feedwater control system, or operator error. Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to an increase in power level. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. The RPS and safety systems are actuated to mitigate the transient. The acceptance criteria are based on critical heat flux not being exceeded, pressure in the RCS and MSS being maintained below 110 percent of the design pressures, and the peak linear heat generation rate not exceeding a value that would cause fuel centerline melt. Specific review criteria are found in the SRP, Section 15.1.1-4.

The licensee used the LOFTRAN computer code to analyze the RCS and core response to the excessive heat removal due to a feedwater system malfunction, with the RSG at EPU conditions. In response N.1 of Reference 2, the licensee addressed the NRC staff's concern on crediting the turbine trip as providing protection against DNB in the excessive feedwater flow case. The analysis performed showed that the minimum DNBR occurred prior to initiation of rod motion and the SAL was not exceeded. Therefore, the reactor trip on turbine trip was not required for core protection. The results of the feedwater flow increase case show the minimum DNBR value reached was 1.75, above the SAL of 1.55. The peak primary pressure reached was 2357 psia, below the safety limit of 2748.5 psia. The peak secondary pressure reached was 1124 psia, below the safety limit of 1208.5 psia. For the feedwater temperature reduction cases, the minimum DNBR reached was 1.67 (SAL is 1.55), the peak primary pressure reached was 2357 psia (limit is 2748.5 psia), and the peak secondary pressure was 914 psia (limit is 1208.5 psia). In response N.2 of Reference 2, the licensee provided the analysis results comparing the transient response using the Model 51 SGs and the Model 54F SGs. The plant response was almost identical. Figures N.2-1 and N.2-3 of Reference 2, letter show the acceptance criteria continue to be met.

The NRC staff reviewed the licensee's analysis and concludes that the licensee's analysis was performed using acceptable analytical models. The NRC staff finds that the licensee demonstrated that the RPS and safety systems will continue to ensure the critical heat flux will not be exceeded and pressure in the RCS and MSS will be maintained below 110 percent of the design pressures. The NRC staff concludes that the analysis performed with the RSG at EPU conditions bounds current licensed power operation with the RSGs. The NRC staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed RSG program. Therefore, the NRC staff finds that the proposed RSGs program is acceptable with respect to the excessive heat removal due to feedwater system malfunction event.

3.9.2.9 Excessive Load Increase Incident (LAR Section 5.3.10)

An excessive load increase incident is an ANS Condition II event that is characterized by a rapid increase in the steam flow to a level beyond that which is needed to match the reactor core power generation. As a result, the core is cooled, and reactivity and power increase to match the higher steam flow. The plant should be capable of tolerating a 10-percent step-load increase or a 5 percent-per-minute ramp load increase in the range of 15 to 95 percent of full power without tripping. This event could be caused by an operator error, or an equipment malfunction in the steam dump control or turbine speed control. The acceptance criteria are based on critical heat flux not being exceeded, pressure in the RCS and MSS being maintained below 110 percent of the design pressures, and the peak linear heat generation rate not exceeding a value that would cause fuel centerline melt. Specific review criteria are found in the SRP, Section 15.1.1-4.

The licensee evaluated this event by verifying that the plant operating conditions, following the steam flow increase, remain within the acceptable operating region defined by the core thermal limits. Supplemental information was provided by the licensee in Section 5.3.10 of Reference 2. Bounding initial conditions for plant parameters which impact DNBR were determined for BVPS-1 at EPU conditions, consistent with the RTDP. The initial conditions included the EPU core power of 2900 MWt, high nominal T_{avg} temperature of 580 EF, nominal RCS pressure with measurement bias of 2242.5 psia, and minimum measured flow of 266,800 gpm, consistent with the RTDP DNB methods. The combined BVPS-1 EPU initial conditions and bounding deviations were compared directly to the EPU core thermal limit lines that represent the locus of conditions when the DNBR is equal to the DNBR limit value for the EPU. The comparison showed that margin between the bounding statepoint conditions and core thermal limits exist, demonstrating that the minimum DNBR conditions associated with an excessive load increase incident for BVPS-1 at EPU meet the EPU safety analysis DNBR limit. Thus, the excessive load increase incident with the RSGs operating at current licensed power level remains bounded.

The NRC staff reviewed the licensee's evaluation of the excessive load increase incident and concludes that the licensee's evaluation demonstrates that the acceptance criteria continue to be met. The NRC staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed RSG program. The NRC staff concludes that the analysis performed with the RSG at EPU conditions bounds current licensed power operation with the RSGs. Therefore, the NRC staff finds that the proposed RSG program is acceptable with respect to the excessive load increase incident.

3.9.2.10 Accidental Depressurization of the RCS (LAR Section 5.3.11)

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 PSV since a safety valve is sized to relieve approximately twice the steam flowrate of a relief valve and will allow a much more rapid depressurization upon opening. The reactor may be tripped on low pressurizer pressure signal or the OTΔT signal. Analysis of the accidental depressurization of the RCS was analyzed as a Condition II event. The acceptance criteria include ensuring minimum DNBR does not go below the safety limit value at any time during the transient and ensuring pressure in the RCS is maintained below 110 percent of the design pressures. Specific review criteria are found in the SRP, Section 15.6.1.

The licensee used the LOFTRAN computer code to analyze the accidental depressurization transient, consistent with the AOR. This accident analysis was performed in accordance with the RTDP methodology in order to calculate the minimum DNBR during the transient. The licensee's analysis results indicated that the inadvertent opening of a PSV would not lead to a violation of the DNB design. The DNBR value calculated by LOFTRAN was 1.62, above the SAL value of 1.55. In response to an NRC staff RAI with respect to crediting the OTΔT trip for this event, the licensee responded to question 17 in Reference 4 that the OTΔT trip setpoints are validated for a window of conditions that ensure the DNB design basis was satisfied. This window was bounded by the low pressurizer pressure and high pressurizer pressure reactor trip setpoints. Therefore, a reactor trip generated by either a low pressurizer pressure or OTΔT trip will ensure that the DNB design basis is satisfied for the RCS depressurization event.

The NRC staff reviewed the licensee's analyses of the inadvertent opening of a PSV event and concludes that the licensee's analyses are performed using acceptable analytical models. The NRC staff concludes that the licensee demonstrated that the RPS and safety systems will continue to provide reasonable assurance that the DNB SAL will not be exceeded. This is a depressurization event and the RCS pressure limits were not challenged. The NRC staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed RSG program. Therefore, the NRC staff finds that the proposed RSG program is acceptable with respect to the accidental depressurization of the RCS event.

3.9.2.11 Steam System Piping Failure (LAR Section 5.3.12)

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 SDM to be lost. 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 to be stuck in its fully withdrawn position. RPS and safety systems are actuated to mitigate the transient. The core is shut down by boric acid injection into the RCS by the SI system. The rupture of a major steam line is the most-limiting cooldown transient. It is analyzed at zero power with no decay heat assumed. Decay heat would partly offset the cooldown, and reduce the post-trip return to power. Although this event is a Condition IV event, it is analyzed to meet Condition II acceptance criteria. The acceptance criteria are based on critical heat flux not being exceeded. The NRC staff's review focused on the core response to the MSLB event. The NRC staff did not verify the requirement of the RCPB being designed with sufficient margin to assure that, under the specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized, were satisfied. Specific review criteria are found in the SRP, Section 15.1.5.

The licensee used the LOFTRAN computer code to simulate the NSSS response to the MSLB transient and to provide dynamic core conditions to the VIPRE thermal-hydraulic code and ANC core physics code. The VIPRE code, employing the W-3 correlation (due to local conditions outside of WRB-1 and WRB-2M applicability range), was used to calculate the DNBR at the limiting time during the transient. These computer models and methods have been previously reviewed and approved by the NRC staff for the MSLB analysis and their application is consistent with the current BVPS-1 AOR. Section 5.3.12.2 of Reference 1 describes the inputs and assumptions used in the analysis. Tables 5.3.12-1A and 5.3.12-1B list the sequence of events of the limiting post-trip MSLB scenarios. In response Q.1 of Reference 2 to an NRC staff RAI regarding the throat area of the integral flow restrictors, the licensee identified that the BVPS-1 RSGs contain a 1.4 ft^2 integral flow restrictor. In addition, the BVPS-1 MSLB event assumed unisolatable steam paths following MSIV closure as evident in RAI response Q.7 of Reference 2.

In response Q.13 of Reference 2, regarding main and AFW flow, the licensee stated that the MSLB analysis conservatively assumed hot full power (HFP) main feedwater flow until main feedwater isolation is complete. Additionally, maximum AFW system flow is conservatively assumed (at minimum AFW enthalpy) to be fed asymmetrically to the faulted loop only, throughout the entire transient. The NRC staff finds these modeling assumptions conservative.

In response Q.15 of Reference 2, regarding the instrumentation response within a harsh environment, the licensee provided a discussion on the qualification of the credited instrumentation and the determination of analytical setpoints. In response Q.18 of Reference 2, the licensee stated that the analyses explicitly model the individual components of the instrumentation delays and lead/lag times.

In response Q.17 of Reference 2 and response 12 of Reference 4, regarding the axially dependent CHF correlations, the licensee described the use of the W-3 correlation with a 0.88 multiplier and a safety limit of 1.45. The application of the W-3 correlation along with this multiplier and limit has been previously reviewed and approved by the NRC staff. A limiting axial power distribution is obtained from an ANC calculation. Figure Q.17-1 of Reference 2 depicts a limiting top skewed hot assembly axial power distribution. In response Q.19 of Reference 2, regarding the initial SG liquid mass inventory, the licensee stated that the initial SG water level was assumed to be at the nominal level for hot zero power (HZP) and that instrument uncertainties do not need to be specifically accounted for. The licensee stated that since the reactivity transient turns around prior to SG dry out conditions, then the inclusion of additional SG liquid mass would have no further effect. An examination of the sequence of events tables and the SG liquid mass versus time transient plots (response Q.7 of Reference 2) revealed that BVPS-1's reactor returned to subcritical condition prior to SG dry out.

During an audit at Westinghouse-Monroeville in November 2005, the NRC staff reviewed the Westinghouse engineering calculations supporting this event. As part of the audit, the NRC staff verified the transfer of transient statepoints between LOFTRAN and VIPRE calculations. Based upon the input parameters, assumptions, and modeling techniques described in Section 5.3.12.2 of Reference 9 and in responses to RAIs contained in References 2 and 4, the NRC staff finds that the post-trip MSLB transient simulation and the identification of the limiting cases are acceptable. The limiting BVPS-1 post-trip MSLB cases demonstrate that the calculated minimum DNBR remains above the DNB SAL of 1.45, ensuring that fuel rod failure does not occur.

Based upon satisfying the more restrictive Condition II acceptance criteria, the NRC staff finds that the results of the BVPS-1, EPU post-trip MSLB analysis are acceptable. The Model 54F RSGs were analyzed for BVPS-1 at EPU conditions and found to be bounding for the current licensed operating power.

The NRC staff reviewed the licensee's analysis of the steam line break and concludes that the licensee's analysis is performed using acceptable analytical models, and that the results meet the DNB design basis and fuel centerline linear power criteria. The NRC staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed RSG program and the NRC staff finds that the proposed RSG program is acceptable with respect to the steam line break at HZP.

3.9.2.12 Partial Loss of Forced Reactor Coolant Flow (LAR Section 5.3.13)

A partial loss of coolant flow, an ANS Condition II event, may be caused by a mechanical or electrical failure in an RCP motor, a fault in the power supply to the pump motor, or a pump motor trip caused by such anomalies as over-current or phase imbalance. The licensee's partial loss of coolant flow accident analysis postulates a failure that causes one RCP to coast down with three loops in operation. The acceptance criteria are based on the critical heat flux not being exceeded and that the peak RCS and MSS pressures remain below 110 percent of their design pressures. Specific review criteria are found in the SRP, Sections 15.3.1-15.3.2.

The licensee used the LOFTRAN computer code to calculate the loop and core flow during the transient, the nuclear power transient, and the primary system pressure and temperature transients. The FACTRAN computer code was then used to calculate the heat flux transient based on the nuclear power and RCS flow from LOFTRAN. The VIPRE code was then used to calculate the DNBR during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN. The event was analyzed using the RTDP assuming initial reactor power, pressurizer pressure, and RCS temperature were at their nominal values for EPU conditions. Assumptions are made such that the core power was maximized during the initial part of the transient when the minimum DNBR was reached. The analysis results indicated that the minimum DNBR was 2.25 for the RFA fuel, and 1.90 for the thimble cell V5H fuel. The primary peak pressure obtained was 2373.8 psia, below the safety limit of 2748.5 psia. The peak secondary pressure obtained was 989 psia, below the safety limit of 1208.5 psia. Therefore, the acceptance criteria continue to be met.

The NRC staff reviewed the licensee's analysis results and concludes that the licensee's analysis is performed using acceptable analytical models and the analysis is bounding for current licensed power operation with the RSGs. The NRC staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed RSG program. Therefore, the NRC staff finds that the proposed RSG program is acceptable with respect to the partial loss of forced reactor coolant flow event.

3.9.2.13 Complete Loss of Forced Reactor Coolant Flow (LAR Section 5.3.14)

A complete loss of forced reactor coolant flow, an ANS Condition III event, may result from a simultaneous loss of electrical power supply or a reduction in power supply frequency to all RCPs. A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer and a subsequent increase in fuel temperature. Accompanying fuel damage could then result if specified acceptable fuel design limits are exceeded during the transient. The RPS and safety systems are actuated to mitigate the transient. The ANS Condition II acceptance criteria were conservatively applied to the analysis of this event. The critical heat flux must not be exceeded, and pressure in the RCS and MSS must stay below 110 percent of the design pressures. Specific review criteria are found in the SRP, Sections 15.3.1-15.3.2.

The licensee analyzed this accident using the RTDP along with the LOFTRAN computer code assuming EPU conditions to calculate the loop and core flow transients, the nuclear power transient, and the primary system pressure and temperature transients, modeling the RSGs. The FACTRAN code was then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. The VIPRE code was used to calculate DNBR during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN. For the complete loss of flow event, the licensee analyzed two transient cases: (1) a loss of power to all pumps and (2) an underfrequency condition. The VIPRE analyses for these scenarios confirmed that the minimum DNBR values of 1.39 (typical cell for V5H fuel) and 1.64 (RFA fuel) were greater than the safety analysis limit values of 1.33/1.55, respectively. The peak RCS and MSS pressures remain below their respective limits (2504.1 psia for RCS and 992.8 psia for MSS) at all times.

The NRC staff reviewed the licensee's analyses of the complete loss of reactor coolant flow and concludes that the licensee's analyses are performed using acceptable analytical models. The NRC staff finds that the licensee demonstrated that the RPS and safety systems will continue to ensure the minimum DNBR will remain above the safety analysis limit and pressure in the RCS and MSS will be maintained below 110 percent of the design pressures. The NRC staff concludes that the analysis performed with the RSG at EPU conditions bounds current licensed power operation with the RSGs. Therefore, the NRC staff finds that the proposed RSG program is acceptable with respect to the complete loss of reactor coolant flow.

3.9.2.14 RCP Shaft Seizure (Locked Rotor)/RCP Shaft Break (LAR Section 5.3.15)

The locked-rotor accident, an ANS Condition IV event, can result from an instantaneous seizure of the RCP rotor or the break of the RCP shaft. Flow through the affected reactor coolant loop is rapidly reduced, leading to a reactor trip on a low flow signal. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer that 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. The licensee considered the most limiting combination of conditions for the locked-rotor and pump shaft break events. In either case, RPS and safety systems were actuated to mitigate the transient. The ANS Condition IV event acceptance criteria were applied as follows:

(1) RCS pressure should be below the designated limit, (2) coolable core geometry is ensured by showing that the peak cladding temperature and maximum oxidation level for the hot spot are below 2700 EF and 16 percent by weight, respectively, and (3) activity release is such that the calculated doses meet 10 CFR Part 100 guidelines. Specific review criteria are found in the SRP, Section 15.3.3-4.

The licensee used the LOFTRAN, FACTRAN, and VIPRE computer codes to analyze this event with the RSG at EPU conditions. The licensee performed the analyses using the LOFTRAN computer code to calculate the loop and core flow transients, nuclear power transient, and RCS pressure and temperature transients. The FACTRAN computer code was then used to study the thermal behavior of the fuel located at the core hot spot. The licensee used the VIPRE computer code to calculate the thermal behavior of the fuel located at the core hot spot including the rods-in-DNB using the input from LOFTRAN and FACTRAN. The cases analyzed to determine rods-in-DNB used the RTDP methodology. Rods-in-DNB cases were analyzed twice, once with continuous operation of the intact RCPs, and once with a loss of power to the intact RCPs to determine RCS pressure and PCT. The results of the analyses showed that the peak RCS pressure was 2716 psia, less than the acceptance criterion of 2997 psia. The PCT was 1868 EF which was considerably less than the limit of 2700 EF for this event. The zirconium-water reaction at the hot spot was 0.41 percent by weight, meeting the criterion of less than 16 percent zirconium-water reaction. The total percentage of fuel rods calculated to experience DNB was less than 20 percent (rods-in-DNB case). In response S.3 of Reference 2, the licensee provided supplemental information on how the percent of rods in DNB were calculated. The total percentage of fuel rods in DNB was less than that assumed in the radiological dose evaluation.

The NRC staff reviewed the licensee's analyses of the locked-rotor and pump shaft break events and concludes that the licensee's analyses are performed using acceptable analytical models. The NRC staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed RSG program. The NRC staff concludes the analyses performed with the RSGs at EPU conditions bound current licensed power operation with the RSGs. Therefore, the NRC staff finds that the proposed RSG program is acceptable with respect to the RCP locked-rotor and pump shaft break accidents.

3.9.2.15 Rupture of a Control Rod Drive Mechanism Housing RCCA Ejection (LAR Section 5.3.16)

Control rod ejection accidents cause a rapid positive reactivity insertion together with an adverse core power distribution that could lead to localized fuel rod damage. The licensee performed an evaluation pursuant to 10 CFR 50.59, and determined that the RSG program would not affect the current analysis. The licensee performed the analyses at EPU conditions and evaluated for operation at the current power level with RSGs for BVPS-1. The licensee concluded the results of that evaluation demonstrated that operation of BVPS-1 at its current power level with the RSGs was bounded by the EPU analyses. Additionally, the dose analysis was previously reviewed and approved by the NRC staff in Amendment No. 257 (Reference 23, ADAMS Accession No. ML032530204). The NRC staff finds that the evaluation is acceptable since, pursuant to 10 CFR 50.59, no changes are being made that would reduce the safety margin for this event for operation at the current licensed RTP with the RSGs.

3.9.2.16 Major Rupture of a Main Feedwater Pipe (LAR Section 5.3.17)

A major feedwater line break (FLB), an ANS Condition IV event, is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the SGs to maintain shell-side fluid inventory. 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 an RCS cooldown (by excessive discharge of steam through the break) or an RCS heatup. Cases that can cause an RCS cooldown were covered by the analysis of the steamline break event, also an ANS Condition IV event. Therefore, a feedwater line rupture was evaluated as one of the events that can cause an RCS heatup. Analysis of this event demonstrates the ability of the AFW system to remove core decay heat and thereby ensure that the core remains in a coolable geometry. It is inferred that the core remains covered with water (and coolable) by showing that the hot and cold leg temperatures remain subcooled until the AFW system heat removal rate exceeds the RCS heat generation rate (mainly from decay heat). The NRC staff's review focused on the NSSS response to the FLB event to provide reasonable assurance that the AFW system, in combination with the RPS and safety systems, had adequate capacity to remove decay heat, to prevent overpressurization of the RCS, and prevent uncovery of the core. Specific review criteria are found in the SRP, Section 15.2.8.

The licensee used the LOFTRAN computer code to analyze the FLB event. The analyses model a simultaneous loss of main feedwater to all SGs and subsequent reverse blowdown of the faulted SG. The LOFTRAN FLB methodology was previously reviewed and approved by the NRC staff and its EPU application was consistent with the current BVPS-1 UFSAR FLB analyses. Section 5.3.17.2 of Reference 1 described the inputs and assumptions used in the analyses. Tables 5.3.17-1A listed the sequence of events of the limiting FLB scenarios for BVPS-1. In response U.2 of Reference 2 and response 2 of Reference 4 regarding the limiting break size, the licensee provided a plot of break size versus margin to hot leg saturation. The NRC staff had concerns that the Westinghouse methodology (which identifies the limiting scenario as the maximum break size) may be incorrect. Examination of the plots provided in response to the RAIs indicates that, contrary to the FLB methodology in WCAP-9230, the largest possible break size may not yield the most conservative results. The break spectrum analysis demonstrated that BVPS-1 continued to satisfy the acceptance criteria for all possible break sizes and therefore, this issue did not need to be specifically addressed for the BVPS-1 RSG program. In response to the RAI, the licensee indicated that an issue report had been entered into the Westinghouse Corrective Action Process (CAP) to investigate the effects of varying break size on the NOTRUMP low SG level (LSGL) trip mass, the break flow enthalpy, and the overall LOFTRAN simulation.

The Westinghouse methodology included the use of NOTRUMP to (1) predict SG inventory as a function of SG liquid level, and (2) predict break flow conditions. The licensing history and interaction between LOFTRAN and NOTRUMP is discussed in response 6 of Reference 4. The FLB methodology, including the interaction between NOTRUMP and LOFTRAN, was consistent with the current UFSAR analyses. In response 1 of Reference 4, regarding a discrepancy with the UFSAR methodology description, the licensee stated that there have been no methodology changes and that the BVPS UFSARs have, since approximately 1981, incorrectly stated the break flow assumptions. The licensee noted that the current FLB methodology for feedring SGs was adopted in the late 1970s and has been widely applied to the Westinghouse fleet. The licensee also stated that the UFSARs would be updated to correctly reflect the break flow assumptions. Based on the application of the current licensing basis approach and the licensee's intent, consistent with 10 CFR 50.71(e), to update its UFSAR, the NRC staff finds this acceptable for the BVPS-1 RSGs.

Nevertheless, the NRC staff had concerns that the modeling uncertainty associated with NOTRUMP's ability to predict dynamic SG liquid level and break flow characteristics were not specifically accounted for. In response 3 of Reference 4, regarding the uncertainty associated with "indicated" SG downcomer liquid level, the licensee stated that, to account for harsh environment instrument uncertainties, a reactor trip and AFW actuations on low SG level are assumed at a SG mass corresponding to 0% NRS. While the modeling uncertainty associated with NOTRUMP's ability to predict indicated liquid level has not been quantified, the licensee stated that the calculated SG mass at the low SG level was conservatively reduced by 10%. Based on these conservative modeling techniques, the NRC staff finds that the credited actuations on indicated SG downcomer liquid level are acceptable.

In response 4 of Reference 4, regarding the uncertainty associated with "actual" SG downcomer liquid level, the licensee stated that the impact of the uncertainty on break discharge characteristics has not been quantified. The NRC staff also had concerns whether each SG design had been adequately evaluated over the range of potential FLB transient conditions. The licensee noted numerous conservative assumptions that were part of the Westinghouse FLB methodology. However, the NRC staff still had concerns that the NOTRUMP modeling uncertainty may adversely effect the transient simulation and the calculated results. In response, the licensee provided a sensitivity study on break discharge quality (Figure 2-3 of Reference 4). The results of this sensitivity study demonstrated that BVPS-1 maintains margin to hot leg saturation even when a saturated liquid discharge was assumed. Therefore, the NRC staff finds that this issue does not need to be specifically addressed to support the BVPS-1 RSG program. The Westinghouse CAP issue report previously identified will investigate these issues on a generic basis.

In response U.3 of Reference 2 and response 2 of Reference 4, regarding the mitigating actions of the power-operated relief valves (PORVs), the licensee stated that the PORVs perform no safety function or mitigating actions and that the PORV operation results in a lower RCS pressure and lower saturation temperature. The NRC staff agrees that for minimizing margin to hot leg saturation, PORV operation is conservative. However, the NRC staff had concerns that PORV operation would minimize RCS peak pressure. In response, the licensee stated that the FLB event was bounded, with respect to peak pressure, by the Loss of Load/ Turbine Trip (LOL/TT) events and that peak RCS and MSS pressure do not need to be calculated for FLB events. While the LOL/TT events challenge peak pressure criteria, the NRC staff noted that these events were design-basis events for primary and secondary safety valve relief capacity. Whereas, the RCS cool-down and subsequent heat-up (RCS pressure rebound) experienced during a FLB event (due to initial SG blowdown followed by reduced heat transfer after faulted SG dryout) was a design-basis event for the AFW system capacity. To assess the impact of the PORV operation on peak pressure, the NRC staff independently re-ran the limiting BVPS-1 FLB LOFTRAN cases (during the audit of the BVPS-1 RSG program at the Monroeville offices of Westinghouse). As expected, the calculated peak RCS pressure increased, but did not approach the 110% of design criteria. These cases demonstrated that the combination of AFW system capacity and operator actions (to isolate faulted SG and increase AFW delivery to 400 gpm at 15 minutes) were adequate to mitigate the pressure rebound transient to less than 110% of design. Therefore, the NRC staff finds this acceptable for the BVPS-1 RSG program.

The NRC staff also had concerns that the RCS heat-up (following faulted SG dryout) may challenge the pressurizer volume capacity and promote liquid discharge from the PSVs. In response 2 of Reference 4, regarding PORV operation and pressurizer fill, the licensee stated that the FLB analysis at EPU conditions had demonstrated that no water relief occurs. The NRC staff's independent LOFTRAN cases confirm that with no credit for PORV operation, pressurizer liquid level remained below the PSV elevation. The NRC staff acknowledged that initial conditions were not targeted to maximize pressurizer fill, instead selected to degrade margin to hot leg saturation. However, the licensee stated that peak pressurizer liquid level occurs no sooner than 20 minutes into the transient with significant margin to overfill. Thus, operators would have sufficient time to diagnose and take mitigating actions (e.g. isolate or limit safety injection) to control pressurizer water level in accordance with plant procedures. The NRC staff finds this acceptable for the BVPS-1 RSG program.

In response U.1 of Reference 2, regarding the instrumentation response within a harsh environment, the licensee provided a discussion on the qualification of the credited instrumentation and the determination of analytical setpoints. The NRC staff finds this acceptable.

Based upon the input parameters, assumptions, and modeling techniques described in Section 5.3.17.2 of Reference 9, and in responses to RAIs in Reference 2 and 4, the NRC staff finds the BVPS-1 FLB transient simulations and the identification of the limiting cases acceptable.

The licensee, as demonstrated by independent NRC staff calculations, provided reasonable assurance that all of the acceptance criteria continue to be met. The BVPS-1 AFW system capacity was adequate to remove decay heat, to prevent overpressurizating the RCS, and to prevent uncovering the reactor core. Based upon satisfying these acceptance criteria, the NRC staff finds that the results of the BVPS-1 FLB analysis conducted at EPU conditions bounds operation at the current licensed power level and is acceptable for the Model 54F RSGs.

The NRC staff reviewed the FLB analyses and concludes that the licensee's analyses adequately account for operation of the plant at the current licensed power level with the RSGs and were performed using acceptable analytical models. The NRC staff further concludes that the licensee demonstrated that the RPS and safety systems will continue to assure 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, the NRC staff concludes that the plant will continue to meet the requirements and finds the proposed RSG acceptable with respect to the FLB transient.

3.9.2.17 Spurious Operation of the SI System at Power (LAR Section 5.3.18)

The licensee evaluated the spurious operation of the SI system at power pursuant to the 10 CFR 50.59 screening process at the current licensed power with the Model 54F RSGs as part of the RSG program and determined that no changes were necessary. However, the licensee addressed the event with the RSG at EPU conditions in Reference 9 as part of the EPU program. The NRC staff agrees with the licensee's assessment since no changes are being made to the RCS parameters that affect the RPS or safety systems associated with this event at the current licensed power level for the RSG program. The licensee provided additional information regarding the qualification of the PSV for water relief. The licensee submitted analyses that do not credit operation of the PORVs, that show the cycling of the PSVs, and provide a transient history of the temperature of the water that is discharged through the PSVs. Thus, it was possible to verify that the discharged water does not become cold enough to invalidate the PSV water qualification bases. For BVPS-1, the temperature of the discharged water was well above the minimum temperature required to qualify its (Target Rock) PSVs for water relief at the current power level as part of the RSG program. The NRC staff concludes that BVPS-1 will continue to meet the regulatory requirements following implementation of the proposed RSG program at the current licensed power. Therefore, the NRC staff finds that the proposed BVPS-1 RSG program is acceptable with respect to the spurious operation of the SI system event. The qualification of the PSV and PORVs at EPU conditions will be addressed later as part of the EPU review.

3.9.2.18 Steam System Piping Failure at Full Power (LAR Section 5.3.19)

The steam system piping failure accident analysis described in Section 5.3.12 of Reference 1 is performed assuming an HZP initial condition with the control rods inserted in the core with the exception of the most reactive rod. Such a condition could occur while the reactor is at hot shutdown at the minimum required shutdown margin or after the plant has been tripped automatically by the RPS or manually by the operator. The purpose of the Section 5.3.19 technical analysis of Reference 1 was to describe the analysis of an MSLB occurring from at power initial conditions to demonstrate that core protection was maintained prior to and immediately following a reactor trip. Depending on the size of the break, the MSLB event is classified as either an ANS Condition III or Condition IV (Limiting Fault) event. However, the licensee performed its analyses of this event to the more restrictive ANS Condition II acceptance criteria. The NRC staff's review focused on the core response to the MSLB event.

The current licensing basis for BVPS-1 does not include a specific assessment of the pre-trip power excursion portion of the MSLB event. The respective sections of the BVPS-1 UFSAR focus solely on the post-trip return-to-power event. This departure from the current licensing basis was necessary to properly assess the potential radiological consequences resulting from the challenge to the fuel design limits experienced during the initial power excursion. The licensee used the LOFTRAN code to simulate the NSSS response to the MSLB transient and to provide dynamic core conditions to the VIPRE thermal-hydraulic code and ANC core physics code. The VIPRE computer code, employing the WRB-1 and WRB-2M correlations above the first mixing vane grid and the W-3 correlation below, was used to calculate the DNBR at the limiting time during the transient. Section 5.3.19.2 of Reference 1 described the input parameters and assumptions used in the pre-trip MSLB analysis. Table 5.3.19-1 of Reference 1 lists the sequence of events of the limiting pre-trip MSLB scenarios. In response W.6 of Reference 2, regarding the break spectrum investigation, the licensee provided a description of the RPS response relative to varying break sizes and identified the limiting break size of 0.6 ft^2 for BVPS-1. The limiting break size corresponds to the intersection of the timing of the overpower Δtemperature (OPΔT) and low steamline pressure reactor trip functions.

In response W.1 of Reference 2, regarding the instrumentation response within a harsh environment, the licensee provided a discussion on the qualification of the credited instrumentation and the determination of analytical setpoints. In response W.4 of Reference 2, to a related RAI, the licensee stated that the analyses explicitly modeled the individual components of the instrumentation delays and lead/lag times. Further, the RCS loop temperature asymmetry was explicitly modeled as an initial condition. In response W.2 of Reference 2, regarding the axially dependent CHF correlations, the licensee described the use of three different correlations within the two fuel assembly designs. For the W-3 correlation (used below the first mixing vane grid), the RTDP methodology did not apply. Therefore, the instrument and monitoring uncertainties were applied directly to the thermal-hydraulic system statepoints in a conservative manner (reducing the calculated DNBR at that statepoint). In response W.3 of Reference 2, the licensee noted that application of the uncertainties to the limiting thermal-hydraulic statepoints was more conservative than the application of these uncertainties to the initial conditions.

During an audit at Westinghouse-Monroeville in November 2005, the NRC staff reviewed the Westinghouse engineering calculations supporting this event. As part of the audit, the NRC staff verified that the transfer of transient statepoints between LOFTRAN and VIPRE calculations, including the application of uncertainties, were done correctly.

In response 9 of Reference 4, regarding the LOOP analysis, the licensee described the LOOP assumptions for the FLB and locked-rotor analyses. With respect to the HFP MSLB, the licensee noted that BVPS-1 had implemented a 30-second delay following an RPS initiated turbine trip before automatic bus transfer to offsite power was attempted. This action delays the potential for RCP coast down until well after the HFP MSLB event is terminated. In response 10 of Reference 4, regarding the fuel temperature and fuel clad strain limits, the licensee stated that both of these criteria have been satisfied for the EPU conditions, assuring that fuel rod failure did not occur.

The NRC staff reviewed the licensee's analysis of the MSLB at full power modeling the RSGs at EPU conditions and concludes that the licensee's analysis is performed using acceptable analytical models and the results meet the DNB design basis and fuel centerline linear power criteria. Based upon satisfying the more restrictive Condition II acceptance criteria, the NRC staff finds that the results of the BVPS-1 MSLB analysis at full power are acceptable for the BVPS-1 RSG program.

3.9.2.19 Anticipated Transients Without Scram (ATWS) (LAR Section 5.8)

The final ATWS rule, 10 CFR 50.62(c)(1), required the incorporation of a diverse actuation of the AFW and turbine trip for Westinghouse-designed plants. The installation of the NRC-approved AMSAC design satisfies the rule. To remain consistent with the basis of the final ATWS rule, the peak RCS pressures reached in the ATWS evaluation must be similar to, or less than, the peak RCS pressures reached in the Letter NS-TMA-2182 (Reference 24), providing the generic ATWS analyses for the limiting 4-loop plant model. There were no TS changes associated with the ATWS analysis at current power level with the RSGs. The ATWS evaluation reconfirmed the adequacy of the AMSAC setpoints. An additional evaluation was performed by the licensee to confirm that the analytical basis for the final ATWS rule will continue to be met with the RSGs at EPU conditions.

The licensee performed an evaluation pursuant to 10 CFR 50.59 (Reference 25), for the ATWS analysis and determined the EPU conditions bound operation with the RSGs at current power level and do not adversely affect design function. In support of a previous RSG project using the Model 54F RSGs, an evaluation of the performance characteristics of the Model 54F RSGs versus the Model 51 SGs was performed by Westinghouse to address the effect of the change in SGs on the generic ATWS analyses. The results of the two analyses demonstrate that the ATWS results with the Model 54F RSGs are less limiting than those of the Model 51 OSGs. The results of the ATWS evaluation using the revised reference 3-loop ATWS model at an NSSS power of 2910 MWt demonstrate that the resulting peak RCS pressures are lower than the peak RCS pressures for the generic 4-loop Westinghouse plant model with the Model 51 SGs. Therefore, the analytical basis for the rule continue to be met for the operation of BVPS-1 with Model 54F RSGs at the current licensed power of 2697 MWt. During an audit at Westinghouse-Monroeville in November 2005, the NRC staff reviewed the Westinghouse engineering calculations supporting this event. As part of the audit, the NRC staff verified that the generic ATWS analysis in place for the Model 51 SGs was applicable to a 3-loop plant with the Model 54F RSGs.

The NRC staff concludes based on the results of the above audit, that the licensee has demonstrated that the analytical basis for the final ATWS rule continues to be met for operation of BVPS-1 with the Model 54F RSGs. The NRC staff concludes that the ATWS analysis is acceptable for the RSG program.

3.9.2.20 Station Blackout (LAR Section 10.7)

Station blackout (SBO) refers to a complete loss of AC power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves a LOOP concurrent with a turbine trip and failure of the onsite emergency AC power system. SBO 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" (AACs). The NRC staff's review focused on the evaluation that the licensee performed (Reference 26) pursuant to 10 CFR 50.59 for this event with respect to the RSGs. The NRC's acceptance criteria for SBO events are based on 10 CFR 50.63. Specific review criteria are found in the SRP Section 8.1, and in Appendix B to SRP Section 8.2.

The NRC staff reviewed the 10 CFR 50.59 evaluation for the SBO event at BVPS-1 for the RSG program. The UFSAR, Section 8.4.6 addresses the SBO rule. BVPS-1 and 2 can be cross-tied electrically in the event of an SBO. BVPS-1 and 2 use the emergency diesel generators (EDGs) at each unit as an ACC power source to operate systems necessary for the required SBO coping duration and recovery. The licensee determined condensate inventory for decay heat removal during an SBO remained adequate at the current power level with the RSGs. The SBO coping capability at the current licensed power level was found to support the RSG change and no system modification was required. The NRC staff agrees that the effects of the RSG program are bounded by the AOR at the current licensed power level and finds that no licensing basis change is required pursuant to 10 CFR 50.59.

3.9.2.21 Steam Generator Tube Rupture (SGTR) Transient (LAR Section 5.4)

The SGTR accident, an ANS Condition IV event, will transfer radioactive reactor coolant to the shell side of the SG as a result of the ruptured tube, and ultimately, into the atmosphere. Therefore, the SGTR analyses with the RSG at EPU conditions were performed to show that the resulting offsite radiation doses will stay within the allowable guidelines and there was margin available so no SG overfilling occurred. Specific review criteria are found in the SRP, Section 15.6.3.

The accident analyzed is the double-ended rupture of a single SG tube using the modified version of the LOFTRAN code referred to as LOFTTR2 and was approved by the NRC in WCAP-10698-P-A (Reference 27). The licensee assumed that the primary-to-secondary break flow following the SGTR resulted in depressurization of the RCS and that reactor trip and SI were automatically initiated on low pressurizer pressure. The licensee performed two separate analyses for the SGTR event. The licensing basis analysis consisted of a thermal hydraulic analysis to provide tube rupture data as input to the BVPS-1 SGTR radiological dose consequence analysis. The licensee also performed an SGTR operational response analysis for the SGTR radiological consequence analysis using the SGTR data. The analyses were based on a full-power average temperature (T_{avg}) operating window of 566.2 °F to 580 °F, and a SG tube plugging level of up to 22 percent. The analyses performed assumed a LOOP. The licensee provided supplemental information in Section 5.4 of Reference 2 regarding input parameters and assumptions.

The licensee's provided response 6 of Reference 4, regarding the time modeled in the analysis to terminate flow through the break. Previously, a condition report documented that more than 30 minutes was required to terminate radioactive steam release from the ruptured SG. Therefore, the break flow termination time modeled for operator response was revised to 51 minutes based on the licensee's analyses. The licensee determined that terminating the primary-to-secondary break flow in 30 minutes actually resulted in a higher primary-to-secondary steam flow out the break than in the case that modeled break flow termination in 51 minutes for the radiological dose consequence analysis. The thermal hydraulic analysis demonstrated that the SGTR licensing basis methodology modeling a break flow termination time of 30 minutes was more limiting and conservative than the operational response analysis with a break flow termination crediting more than 30 minutes. The NRC staff finds that modeling the break at 30 minutes for a thermal hydraulic point is acceptable since this was a more conservative approach for calculating the radiological dose release.

During an audit at Westinghouse-Monroeville in November 2005, the NRC staff reviewed the inputs to the Westinghouse engineering calculations for the thermal hydraulics analyses supporting this event and found them acceptable. The operational response analysis with the RSG at EPU conditions showed a break flow termination time greater than 60 minutes and margin available so that no overfill occurred.

The NRC staff reviewed the licensee's analyses of the SGTR event and concludes that the licensee's analyses are performed using acceptable analytical models and bound operation at the current power of 2697 MWt with the RSGs. The NRC staff finds that the SGTR event analyses for the proposed RSG program at EPU conditions are acceptable since the analyses inputs and steam release values are conservative for this event and no overfilling occurrs.

3.10 Reactor Trip System (RTS)/Engineered Safety Feature Actuation System (ESFAS) Setpoints (LAR Section 5.10)

For BVPS-1, the Model 54F RSG modification impacts the RTS/ESFAS functions and setpoints for the SG low-low water level reactor trip and AFW actuation; and the SG high-high water level turbine trip and feedwater isolation actuation. The setpoint analysis used the square root sum of the squares (SRSS) technique to combine the uncertainty components of an instrument channel in an appropriate combination of those components, or groups, of components that are statistically independent. The setpoints for these RTS/ESFAS functions were revised to address the design of the Model 54F RSGs, and to optimize operating margins at EPU conditions with the Model 54F RSGs. These SG low-low and high-high water level setpoints were calculated consistent with the recommendations in NSAL-03-9 and Technical Bulletin (TB) TB-04-12 (References 28 and 29, respectively). The results and conclusions of the analyses and evaluations performed for RTS/ESFAS setpoints for the reactor power of 2900 MWt bound and support operation at the current reactor power of 2689 MWt with the RSGs. Following review of the analyses that credit these trips, the NRC staff agrees that the trip setpoints with the RSGs at EPU conditions meet the accident analyses acceptance criteria and there is no reduction in safety margin introduced due to this change. The NRC staff addresses the changes to the SG low-low and high-high water level setpoints in more detail in Section 3.11, parts (2) and (4) below.

3.11 Technical Specifications Changes (LAR Attachment 1)

(1) TS 2.1.1.1 Safety Limits (SLs)

The licensee proposed to modify the TS to specify two different DNB correlations. For V5H fuel assemblies, the correlation was WRB-1 and the DNBR shall be maintained $ 1.17. For RFA, the correlation was WRB-2M, and the DNBR shall be maintained $ 1.14. This change was made to support enhanced fuel performance. Presently, TS 2.1.1.1 only specifies the WRB-1 correlation and its associated limit on DNBR. The WRB-1 correlation is applicable for both V5H and RFA fuel assemblies, but is conservative for the RFA assemblies. The BVPS-1 core may contain solely RFA fuel assemblies, or a mixture of RFA fuel assemblies and previously burned V5H fuel assemblies. With the proposed change, this TS will provide a fuel assembly specific DNBR limit and applicable correlation. The licensee provided the thermal hydraulic analyses associated with the TS changes associated with the use of the STDP, the RTDP, and the W-3, WRB-2, and WRB-2M correlations throughout Section 5.3 of Reference 1. The analyses performed demonstrated that the RFA and V5H fuel assemblies are hydraulically compatible, and that sufficient DNBR margin was available such that the safety limits were not exceeded. Additionally, the licensee addressed and met each of the conditions found in Reference 18, addressing the WRB-2M correlation. The addition of WCAP-15025-P-A to TS 6.9.5 is needed to include the WRB-2M correlation in TS 2.1.1.1. The results of the safety analyses show that the DNBR limit is met when applying this correlation. Therefore, the NRC staff finds that the use of the WRB-2M correlation DNBR value of $ 1.14 is acceptable.

(2) TS Table 3.3.1.1 RPS Instrumentation

This TS change consisted of revising the value for Functional Unit 14, SG water level low-low, to reflect the RSGs. The SG water low-low level channels are part of the RPS and ESFAS. Two of the three SG channels in any SG are required to trip the reactor and start the AFW pumps for protection of the reactor from a loss of heat sink in the event of a sustained steam and feedwater flow mismatch. The proposed TS change would decrease the allowable value (AV) of the SG water low-low level from 19.6 percent to 19.1 percent of narrow range and make the new trip setpoint 19.6 percent. The BVPS-1 Model 54F RSGs incorporate an NRS of 212 inches, which is larger than the current Model 51 OSG NRS of 144 inches. This design difference required that the SG low-low water level trip setpoint and AV be revised. The methodology used for the proposed trip setpoint and AV change was defined in WCAP-11419-P-A (Reference 30). The NRC staff previously reviewed and approved this methodology and related SG water level measurement uncertainties as it affects TS 3.3.1.1 in the SE supporting TS Amendment Nos. 270 and 152 for BVPS-1 and 2, dated January 11, 2006 (Reference 31). This methodology accounted for the SG level uncertainties in a conservative manner. Section 3.1 of the referenced SE addressed two notes that were added to the TSs with respect to meeting the as-found acceptance criteria for the AV. The licensee re-analyzed the LONF and FLB events crediting the SG water low-low level trips with the proposed setpoint stated in Table 5.3.1-3A of Reference 1.

Upon review of the accident analyses crediting the SG low-low level trip setpoint with the RSG, the NRC staff finds that the new values are acceptable since the safety analyses acceptance criteria continue to be met for the events crediting the SG water low-low level trip and since the licensee used an approved methodology that accounts for uncertainties in a conservative manner.

(3) TS 3.3.1.1 Reactor Trip System Instrumentation

This TS change consisted of modifying the OTΔT and OPΔT equations. Currently, the BVPS-1 OTΔT and OPΔT equations do not include lag compensators. The proposed equations were revised to include the addition of lag compensators. The proposed lag compensators for the OTΔT and OPΔT equations were annotated as T_4 and T_5 in the BVPS-1 TSs. The addition of lag compensators will modify the existing BVPS-1 OTΔT and OPΔT equations such that lag compensation is consistent with the mathematical form shown in Reference 32. The proposed OTΔT and OPΔT parameters were established to optimize operational margin within the constraints of the safety analysis provided in Section 5.3 of Reference 1. In response to an NRC staff RAI regarding effects of the change on the plant, the licensee provided response 4 of Reference 4, stating there will be no additional effects on the plant due to this change. BVPS-1 will be in compliance with the safety analyses for the RSG and EPU submittals with the addition of the lag compensators and rescaling of instrumentation racks for BVPS-1. To address the non-LOCA analyses, bounding analyses were performed at 2900 MWt using the revised OTΔT and OPΔT setpoints and time constants. For BVPS-1, the accident analyses show that the DNB design basis is met and there is no reduction in safety. The OPΔT trip is credited in the EPU steam line break analyses. The results and conclusions of the analysis performed for the steam system piping failure at a power level of 2900 MWt bound and support operation at the current power level of 2689 MWt. The steam line break transient did not adversely affect the core or RCS, and all applicable criteria continue to be met. The NRC staff finds that these changes are acceptable since the DNB design criteria is not exceeded and the mitigation function to protect against DNB continues to be met.

(4) TS 3.3.2.1 Engineered Safety Feature Actuation System Instrumentation

This TS change consisted of an editorial change revising the SG water low-low level value on Table 3.3-3 to reflect the RSGs and to be consistent with TS change (2) above. Additionally, an editorial change was made to Functional Units 5.a to read “2/loop” instead of “2 loop”. These changes are editorial in nature and as such, there was no reduction in the safety margin. Therefore, the NRC staff finds that this TS change is acceptable.

The licensee proposed to revise Table 3.3-3, Functional Unit 5.a , SG water high-high level AV from 81.7 percent to 90.2 percent and the trip setpoint to 89.7 in accordance with NSAL-03-9 and TB-04-12 for the RSGs. The SG water high-high level signal functions to prevent the SGs from overfilling with water and avoid overloading effects of water during an excess feedwater flow event on the design of the steam piping supports. The methodology used for the proposed trip setpoint and AV changes was defined in Reference 30. The NRC staff previously reviewed and approved this methodology and the TS amendment related to SG water level measurement uncertainties as it affects TS 3.3.2.1 in Reference 31. This methodology accounted for the SG level uncertainties in a conservative manner. Section 3.1 of the referenced SE addressed two notes that will be added to the TS with respect to meeting the as-found acceptance criteria for the AV. The licensee re-analyzed the excessive heat removal due to feedwater system malfunction event (Section 5.3.9) and provided the analysis results for the RSGs in Reference 2. The results demonstrated the acceptance criteria continue to be met for this event.

After reviewing the accident analysis crediting the SG water high-high level trip setpoint with the RSG, the NRC staff finds that the new values are acceptable since the safety analyses acceptance criteria continue to be met and the licensee uses an approved methodology that accounts for uncertainties in a conservative manner to calculate the proposed values.

(5) TS 3.4.1.3 Reactor Coolant System-Shutdown

This TS change consisted of revising the SG secondary side level requirement in SR 4.4.1.3.3 acceptance criteria from 12 percent to 28 percent to reflect the RSGs. The wording of SR 4.4.1.3.3 was also revised by replacing the word “equivalent” with the words “greater than or equal” for consistency with the Standard Technical Specifications. By satisfying this requirement, the water level will be maintained above the top of the tube bundle, assuring the RSGs will be capable of providing the heat sink necessary for removal of decay heat in Modes 4 and 5. The licensee provided additional information in Reference 6 to demonstrate operability of the RSGs in Modes 4 and 5. The TS water-level requirement of 28 percent NRS was established for the RSGs based on instrumentation uncertainty and setpoint calculations. The licensee used the SRSS in calculating the NRS. The RSG narrow range instrument taps are located at distances of 374.8 inches (lower level tap) and 586.8 inches (upper level tap) above the top of the tube sheet. During an audit at Westinghouse-Monroeville in November 2005, the NRC staff reviewed the Westinghouse engineering calculations for the RSG modification and finds them to be acceptable. The NRC staff finds that this proposed TS change is acceptable since the design function licensing basis will continue to be met and there is no reduction in safety margin.

(6) TS 3.5.5 Emergency Core Cooling Systems-Seal Injection Flow

The proposed revision to TS 3.5.5 consists of two changes. The first change proposes to increase the minimum value of the charging pump (CP) discharge pressure for RCP seal injection flow. The second change proposes to increase the RCS pressure values in the Note for TS SR 4.5.5 by 5 psi to be consistent with current normal operating pressure of 2235 psig.

The purpose of this change was to reflect the analytical resistance used for the RCP seal injection flow path in the calculation of SI flow for the EPU conditions. The purpose of the TS limit on RCP seal injection flow is to limit the flow through the RCP seal water injection line following a safety injection system (SIS) actuation signal so that sufficient high-head safety injection (HHSI) flow is directed to the RCS via the SI points. The flow line resistance was determined by assuming that the RCS pressure was at normal operating pressure and that the centrifugal CP discharge pressure was greater than or equal to the value specified in the TSs. A flow limit was established with the discharge pressure and control valve position as specified in the TSs. It was this flow limit that was used in the accident analyses.

The normal power operation SR for the CP discharge pressure will be increased from 2397 psig to 2457 psig for BVPS-1 to be consistent with the revised safety analyses supporting the RSG LAR. To address SBLOCA impact, a bounding analysis was performed at 2900 MWt using the revised SI flows. The TS and corresponding SR are based on a maximum flow rate because the surveillance is actually verifying that a minimum friction loss coefficient (consistent with the analytical value modeled in the SIS flow analyses) exists for the seal injection lines. Restricting the seal injection resistance to a minimum value assured that a limited amount of seal injection flow was diverted to the seals during SI actuation. The increased minimum discharge pressure functioned to limit the flow to the RCP seals when CPs were operating as HHSI pumps, thereby improving HHSI flowrate for a postulated SBLOCA. The licensee provided additional information in response E.2 of Reference 5 addressing the modifications performed to the HHSI pumps in order to achieve the HHSI pump head flow curves for the SBLOCA analyses conditions. The performance of the SIS was also verified in the SGTR and MSLB events. During an audit at Westinghouse-Monroeville in November 2005, the NRC staff reviewed the Westinghouse engineering calculations and pump head curves for the discharge pressure modification and finds them to be acceptable based on the safety analyses performed, since the CP provided adequate injection flow to perform its HHSI design function and the margin of safety was not reduced. The NRC staff finds that these proposed TS changes are acceptable since the acceptance criteria continue to be met.

(7) TS 6.9.5.b Core Operating Limits Report

This proposed TS change consists of making a conforming editorial change by adding WCAP-14565-P-A, “VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-

LOCA Thermal Hydraulic Safety Analysis", and WCAP-15025-P-A, "WRB-2M Correlation," to the list of NRC-approved methodologies in TS 6.9.5. The licensee requested NRC approval to use the VIPRE computer code and the WRB-2M correlation at BVPS-1. The VIPRE computer code is used for DNB analysis for those UFSAR transients and accidents where DNB is a concern. The NRC staff reviewed the use of the code and correlation in the BVPS-1 accident analyses found in Section 5.3 of Reference 1. The NRC staff addresses the acceptability of these methods in Section 3.9.2 of this SE. The NRC staff finds that this editorial change is acceptable.

(8) TS 3.5.1 Accumulators

A supplement to Reference 1 to include proposed accumulator TS changes was submitted by letter dated October 28, 2005 (Reference 33) for NRC staff review and approval. The accumulators are filled with borated water and pressurized with nitrogen gas. During normal operation, each accumulator is isolated from the RCS by two check valves in series. If the RCS pressure falls below the accumulator pressure, the check valves open and borated water is forced into the RCS. The accumulators are passive ESF because the nitrogen gas pressure forces injection. One accumulator is connected to each of the cold legs of the RCS. The specified TS values for usable accumulator volume, boron concentration, and minimum pressure are values used in the accident analyses.

This proposed TS change consisted of increasing the BVPS-1 TS 3.5.1.d accumulator pressures from a range of 605-661 psig to a range of 611-685 psig. This proposed TS change will increase the BVPS-2 TS 3.5.1.d accumulator pressures from a range of 585-665 psig to a range of 611-685 psig. This proposed TS change will also revise the water volume in the BVPS-1 TS 3.5.1.b from a range of 7664-7816 gallons to a range of 6681-7645 gallons. The water volume in the BVPS-2 TS 3.5.1.b will also be revised from 7532-7802 gallons to 6898-8019 gallons of borated water. The licensee proposed these TS changes in order to be consistent with the SBLOCA analyses performed at EPU conditions supporting Reference 9. The licensee verified there were no effects from these changes on other transients analyses.

These proposed TS changes were reviewed considering the current licensed RTP with the RSGs and are found acceptable since increasing the accumulator pressures will reduce the magnitude of the calculated PCTs for SBLOCAs, where accumulator injection terminates the clad surface temperature rise. Breaks currently controlled by high pressure SI, where the RCS pressure decreases to a value just above the previously approved maximum accumulator pressure injection point, will also benefit. The increased accumulator pressure for these breaks increases ECCS performance following a SBLOCA since earlier actuation of the accumulators will tend to reduce the calculated PCT. Therefore, the NRC staff finds that this change is acceptable.

The licensee also proposed to add the word "usable" in TS 3.5.1.b and replace the word "contained" with "usable" in TS 4.5.1.a to be consistent with the accident analyses inputs. The NRC staff finds that this change is conservative since it limits the minimum borated water that must be available in order for the accumulator to remain operable. Therefore, the NRC staff finds that this change is acceptable.

The NRC staff finds that these proposed TS changes are acceptable since the proposed change in accumulator pressures and volumes are more conservative and are bounding for the

RSG at current licensed RTP. The PCT limits in 10 CFR 50.46 will continue to be met. The approval of the request to increase accumulator pressures does not constitute approval of the analytical methods and results of the SBLOCA and post-LOCA long-term cooling analysis submitted as part of Reference 9.

(9) Changes to current TSs which are inappropriate or unnecessary because of the RSGs

BVPS-1 currently has three Westinghouse model 51 recirculating SGs with mill-annealed Alloy 600 tubing and tube support plates made of carbon steel. The RSGs are Westinghouse Model 54F and incorporate a number of design and material improvements relative to the Model 51 SGs.

The RSGs contain tubes fabricated from thermally treated Alloy 690 material as well as Type 405 stainless steel tube support plates and anti-vibration bars. The thermally treated Alloy 690 tubing material is more resistant to stress-corrosion cracking than mill-annealed Alloy 600 tubing material. The design of the RSGs is intended to improve the operation, maintainability, and accident tolerance of the SGs.

All alternate tube repair criteria (voltage based repair criteria and W*), SG tube sleeving (TIG, laser and Alloy 800 welded sleeving) and their bases will be deleted from TS 3.4.5 since these requirements are no longer needed for the RSGs. All references to all volatile treatment criteria (AVT) will be deleted from the TSs because the RSGs will always be operated with AVT as are the current SGs. All references to “Repair Limit” will be changed to “Plugging Limit” due to the removal of the sleeving (i.e., repair) requirements from the TSs.

In addition, the licensee clarified the inspection frequency to indicate that an inservice inspection is not needed during the replacement outage. The licensee also made several administrative changes involving format and renumbering. The NRC staff has determined that the proposed changes are consistent with the STSs and that there is adequate assurance that the health and safety of the public will not be adversely affected by operation of BVPS-1 after the amendment is implemented. Therefore, the NRC staff concludes that the proposed changes are acceptable.

3.12 MSLB Mass and Energy Release Outside Containment (LAR Section 5.6.2)

Steamline ruptures occurring outside the reactor containment structure may result in significant releases of high-energy fluid to the structures surrounding the steam systems. During the NRC staff review of the Westinghouse Topical Report WCAP-8822 (Reference 34), the NRC staff noted that the heat transfer to the steam from the uncovered portion of the SG was unaccounted for. Through Information Notice No. 84-90 (Reference 35), the NRC staff requested that licensees review their MSLB analyses with regard to this issue. Westinghouse responded to this Information Notice by performing calculations of the steam line break mass and energy release and presented the results in WCAP-10961 (Reference 36). Reference 36 provided the results of the steam line break mass and energy releases necessary for licensees to address the issue of environmental qualification of equipment.

BVPS-1 was included as part of the Category-4 plants in the analysis in Reference 36. The Reference 36 analysis used Model 51 SGs and a power level of 102% or 2660 MWt. The licensee re-analyzed the mass and energy release resulting from a steam line break outside containment using power levels at EPU conditions associated with the Model 54F RSGs to ensure environmental qualification of equipment.

The licensee performed its calculation to maximize the energy released out of the break at every point in the transient. The licensee discussed two types of calculations it performed. The first was consistent with the current licensing basis analysis in Reference 36 that minimized the time to achieve SG tube uncovery, and maximized the superheated release duration and superheated steam enthalpy. The licensee stated that maximizing the value of the steam enthalpy may tend to lower the break flow rate that may have the net result in lowering the total energy release out the break. To capture this effect the licensee performed a calculation in which they increased the time to superheat steam conditions and maximized the “soak time” to get higher total energy releases. The licensee used the more conservative values of the two calculations to perform its environmental qualification of equipment. This would generally result in using mass and energy release values from the maximum enthalpy calculation for the early part of the transient and using the values from the maximum “soak time” calculation in the long term part of the transient.

The NRC staff reviewed all of the input parameters and assumptions for both the maximum enthalpy and maximum “soak time” approaches described in Section 5.6.2 of Reference 1. The licensee calculated core decay heat generation based on the 1979 ANS Decay Heat +2σ model (Reference 22). This is a deviation from the analysis in Reference 36 which used the 1971 ANS Decay Heat Standard +20%. The NRC staff reviewed the licensee’s use of the 1979 ANS Decay Heat Model. In response to an NRC staff RAI, the licensee described its implementation of the decay heat standard in Reference 4. The NRC staff reviewed the licensee’s assumptions listed below and finds them acceptable.

5. The licensee used values from plant data to calculate actual U-238, U-235, and Pu-239 fission fractions.

6. The licensee included contributions from U-239 and Np-239 and calculates their contributions based on Equations 14 and 15 in Reference 22.

7. The licensee assumed 200 MeV total recoverable energy per fission with a standard deviation of 1.5%. This value is consistent with other approved implementations of Reference 22.

8. The irradiation time was chosen to bound the actual burnup level of the specific bundle considered.

9. Neutron capture was defined by Equation 11 in Reference 22.

The NRC staff finds that the licensee used realistic values from plant data where possible, and otherwise used conservative assumptions or those consistent with the guidance in Reference 22. The NRC staff finds the licensee’s use of the 1979 ANS Decay Heat +2σ model acceptable for use in the calculation of mass and energy release following a steam line break outside containment for BVPS-1. The NRC staff reviewed all of the other input parameters and assumptions for both the maximum enthalpy and maximum “soak time” approaches. The NRC staff finds that these input parameters are consistent with the methodology used to determine the current licensing basis and therefore, they are acceptable. The NRC staff finds that those input parameters and assumptions associated with the maximum "soak time" are appropriate and acceptable.

Based upon the licensee's consistency with current licensing basis analysis methods, its use of conservative methods to calculate energy release at all times during the transient, and appropriate use of the 1979 ANS Decay Heat Standard, the NRC staff finds that the licensee's evaluation of mass and energy release outside containment is acceptable for use in determining the environmental qualification of equipment.

3.13 Conclusions

The NRC staff reviewed the licensee's evaluations, analyses and proposed TS changes to support operation of BVPS-1 under the proposed RSG program. Based on its review, the NRC staff finds that the supporting safety analyses were performed with NRC-approved computer codes and methods; the input parameters of the analysis adequately represent the plant conditions for the RSG program assumed in each analysis; and the analytical results were within the licensing basis acceptance criteria. The NRC staff also finds that the licensee met the limitations and conditions stated in the referenced SEs for the WRB-2M and the VIPRE methodologies. Therefore, the NRC staff concludes that the supporting analyses are acceptable. The NRC staff also finds that the proposed TS changes discussed in Section 3.11 adequately reflect the results of the acceptable supporting analyses. Therefore, the NRC staff concludes that the proposed TS changes are acceptable for the implementation of the RSG program for BVPS-1. Additionally, the NRC staff finds that the licensee's use of the 1979 ANS Decay Heat +2 sigma model is acceptable for use in the calculation of mass and energy release following a steam line break outside containment for BVPS-1 as stated in Section 3.12 of this SE.

4.0 Radiological Dose Assessment

4. 1 Radiological Consequences of DBAs

The current BVPS-1 DBAs analyzed for the radiological consequences at the EAB, LPZ, and CR in Section 14, "Accident Analyses" of the BVPS-1 UFSAR include the following nine events:

- LOCA
- Control Rod Ejection Accident (CREA)
- Fuel-Handling Accident (FHA)
- MSLB Accident Outside Containment
- SGTR Accident
- RCP Locked-Rotor Accident (LRA)
- Loss of AC Power (LACP) Accident
- Small Line Break Accident (SLBA) Outside Containment
- Waste Gas System Rupture Event (WGSR)

The licensee previously requested a selective implementation of the AST for the FHA in a submittal dated March 19, 2001. The NRC staff approved the FHA radiological consequence analysis with Amendment No. 241, dated August 30, 2001 (ADAMS Accession No. ML012330496). In this RSG LAR, the licensee stated, and the NRC staff agrees, that the radiological consequence of the FHA is not impacted by the RSGs since there are no new or irradiated fuel movements associated with the RSGs.

Subsequently, the licensee requested another selective implementation of the AST for the LOCA and CREA in their submittal dated June 5, 2002. The NRC staff approved the LOCA and CREA radiological consequence analyses with Reference 23. In this RSG LAR, the licensee stated, and the NRC staff also agrees, that the radiological consequences of the LOCA and the leakage from the containment for the CREA are not impacted by the RSGs since there is no accident initiated fuel damage associated with the RSGs. For the radiological consequence evaluation of the CREA secondary release via primary-to-secondary leakage in Reference 23, the licensee used the RSG thermal hydraulic parameters. The NRC staff audited and confirmed the use of the RSG thermal hydraulic parameters in support of Reference 23.

Therefore, the licensee has previously provided an acceptable evaluation of the impact of the RSGs on the radiological consequences of the CREA for BVPS-1.

For the WGSR event, the licensee stated, and the NRC staff agrees, that the RSGs will have negligible impact on the current licensing basis. The slight change in the primary coolant mass due to the RSGs (368,000 pounds mass (lbm) vs. 373,100 lbm for the current and RSGs, respectively) will have minimal impact on the current design-basis primary coolant source terms; consequently, the RSGs will have negligible impact on the radiological dose consequences.

Therefore, to support this RSG LAR, the licensee analyzed the following remaining five DBAs which were directly impacted by the RSGs:

- MSLB Accident Outside Containment
- SGTR Accident
- Reactor Coolant Pump LRA
- LACP Accident
- SLBA Outside Containment

On November 29 and 30, 2005, the NRC staff met with the licensee at the BVPS site and the NRC staff performed an audit on the five radiological consequence analyses listed above and the associated dose calculations at the EAB, LPZ, and CR. The NRC staff also performed independent confirmatory dose calculations for those five events using an NRC-sponsored radiological consequence computer code, "RADTRAD: Simplified Model for RADionuclide Transport and Removal And Dose Estimation," Version 3.03, as described in NUREG/CR-6604. The RADTRAD code, developed by the Sandia National Laboratories for the NRC, estimates transport and removal of radionuclides and radiological consequence doses at selected receptors.

4.1.1 MSLB Outside Containment

The MSLB accident considered is the complete severance of the largest main steam line outside containment. The radiological consequences of an MSLB outside containment will bound the radiological consequences of a break inside containment. Thus, only the MSLB outside of containment is considered with regard to the radiological consequences. The radiological consequence analysis of this event was performed at an extended reactor core power level of 2918 MWt, which bounds the current licensed reactor core power level of 2689

MWt.

In the MSLB accident scenario, a reactor trip occurs, main steam isolation occurs, safety injection actuates, and a loss of offsite power (LOOP) occurs concurrently with the reactor trip. The licensee assumed that the faulted SG will rapidly depressurize and boil dry, releasing the entire content of liquid inventory and entrained radionuclides of the faulted SG instantaneously to the environment. Steam is released directly from the steam line break point from the faulted SG to the environment. Because the LOOP renders the main condenser unavailable, the plant is cooled down by the release of steam to the environment via the main steam safety valves (MSSVs) and atmospheric discharge valves (ADVs) in the intact SGs until the residual heat removal (RHR) system starts shutdown cooling. There are a total of three SGs. The MSLB accident is described in the BVPS-1 UFSAR, Section 14.2.5, "Major Secondary System Pipe Rupture." Appendix E of RG 1.183 identifies acceptable radiological analysis assumptions for an MSLB.

The licensee stated that no fuel damage is postulated to occur because of an MSLB. The licensee stated in the BVPS-1 UFSAR that the design basis with regard to DNB is met for any steam line rupture, assuming the most reactive rod cluster control assembly is stuck in its fully withdrawn position. The NRC staff previously accepted the DNB analysis in the BVPS-1 UFSAR as a design basis and this assumption is not impacted by the RSGs or implementation of the AST. Consistent with the guidance provided in RG 1.183, the licensee assumed the released activity is the maximum reactor coolant activity specified in the BVPS-1 TSs since there is no postulated fuel damage associated with this event.

Two radioiodine spiking cases are considered. The first assumes that a pre-incident radioiodine spike occurred just before the event and the RCS radioiodine inventory is at the maximum value (21 μCi/gm) permitted by the TSs. The second case assumes that the event initiates a co-incident radioiodine spike. Radioiodine is released from the fuel to the RCS at a rate 500 times the normal radioiodine appearance rate for a duration of 4 hours. The iodine spiking duration of 4 hours is the current design basis in the BVPS-1 UFSAR and this value was reviewed and accepted by the NRC staff previously in Reference 23 as a design basis. The RSGs or the expanded selective implementation the AST does not impact the iodine spiking duration.

Leakage from the RCS to the SGs is assumed to be the maximum value permitted by the TSs (150 gallons per day (gpd) per SG). The maximum TS limit for all three SGs is 450 gpd. The release from the faulted SG due to primary-to-secondary leakage continues for 19 hours until the RHR system brings the primary coolant temperature down to 212 EF. The primary coolant leakage into the faulted SG is assumed to immediately flash to steam and be released to the environment without holdup or dilution. The leakage in the intact SGs mixes with the secondary coolant bulk water and is released through the MSSVs and ADVs at the assumed steaming rate. This steaming from the intact SGs is assumed to continue for 8 hours until shutdown cooling is initiated via operation of the RHR system. The licensee assumed an iodine partitioning factor of 100 in the intact SGs, and assumed no iodine partitioning in the faulted SG.

The licensee conservatively assumed manual initiation of the control room emergency ventilation system (CREVS) at 30 minutes following the MSLB event to pressurize the CR. The

CR is purged at a rate of 16,200 cubic feet per minute (cfm) for a period of 30 minutes beginning at 24 hours following the MSLB event (see Section 4.2, "Control Room Habitability").

The licensee re-evaluated the radiological consequences resulting from the postulated MSLB accident for operation with the RSGs and concluded that the radiological consequences at the EAB, LPZ, and CR are within the dose guidelines provided in 10 CFR 50.67 and accident dose criteria specified in SRP, Section 15.0.1. The NRC staff's audit found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 4 and the licensee's calculated dose results are given in Table 1. The NRC staff performed an independent confirmatory dose calculation to verify the licensee's results. The NRC staff finds that the EAB, LPZ, and CR doses estimated by the licensee for the MSLB meet the applicable accident dose criteria and are therefore, acceptable.

4.1.2 SGTR

The accident considered is the complete severance of a single tube in one of the SGs, resulting in the transfer of RCS water to the ruptured SG. The primary-to-secondary break flow through the ruptured tube following an SGTR results in radioactive contamination of the secondary system. For this accident scenario, a reactor trip occurs, SI actuates, and a LOOP occurs concurrently with the reactor trip. Because the LOOP renders the main condenser unavailable, the plant is cooled down by release of steam to the environment.

The conservatism of the licensing basis thermal hydraulic analysis model, which includes a 30-minute isolation time, is supported by a supplemental BVPS-1 SGTR operational response analysis (ORA) performed by the licensee. The supplemental SGTR ORA included consideration of single active failures, the timing of operator actions in accordance with plant emergency operating procedures, and demonstrated performance during simulator exercises. The licensee stated, in an August 26, 2005, response to the NRC staff's RAI that the ORA and the radiological consequence analysis confirmed that dose estimates using the licensing basis thermal hydraulic analysis model are conservative and bound the dose estimates developed utilizing the thermal hydraulic input data based on the operational response case.

Appendix F of RG 1.183 identifies acceptable radiological analysis assumptions for an SGTR and this event is described in the BVPS-1 UFSAR, Section 14.2.4, "Steam Generator Tube Rupture." Two radioiodine spiking cases are considered. The first assumes that a pre-incident radioiodine spike occurred just before the event and the RCS radioiodine inventory is at the maximum value (21 µCi/gm) permitted by the BVPS-1 TSs. The second case assumes the event initiates a co-incident radioiodine spike. Radioiodine is released from the fuel to the RCS at a rate 335 times the normal radioiodine appearance rate for 4 hours. As stated in Section 4.1.1 above, the iodine spiking duration of 4 hours is assumed. Primary-to-secondary leakage is assumed to be 150 gpd into the bulk water of the ruptured SG and 300 gpd total into the bulk water of the two intact SGs as permitted by the BVPS-1 TSs.

The iodine activity from the break flow through the ruptured SG is assumed to be directly released to the environment and partitioning of iodine is not credited. The radionuclides in the intact SGs bulk water are assumed to become vapor at a rate that is a function of the steaming rate for the SGs and the partition coefficient. The licensee assumed that the radionuclide concentration in the SG is partitioned such that 1 percent of the radionuclides in the unaffected SGs bulk water enter the vapor space and are released to the environment. The steam release from the unaffected SGs continues for approximately 8 hours until the RHR shutdown cooling system can be used to complete the cooldown.

The licensee claimed no credit for fission product removal by the CREVS following an SGTR event and assumed the control room is maintained in normal ventilation mode. Following termination of the environmental release at 8 hours, the CR is purged at a rate of 16,200 cfm for a period of 30 minutes (see Section 4.2, “Control Room Habitability”).

The radiological consequence analysis of this event was performed at an EPU reactor core power level of 2918 MWt which bounds the current licensed reactor core power level of 2689 MWt. The licensee re-evaluated the radiological consequences resulting from the postulated SGTR accident for operation with the RSGs, and concluded that the radiological consequences at the EAB, LPZ, and CR are within the dose guidelines provided in 10 CFR 50.67 and accident dose criteria specified in SRP, Section 15.0.1. The NRC staff’s audit found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE and with those stated in the BVPS-1 UFSAR as the design bases. The assumptions found acceptable to the NRC staff are presented in Table 5 and the licensee’s calculated dose results are given in Table 1. The NRC staff performed an independent confirmatory dose calculation to verify the licensee’s results. The EAB, LPZ, and CR doses estimated by the licensee for the SGTR accident are found to meet the applicable accident dose criteria and are therefore, acceptable.

4.1.3 LRA

The accident considered is the instantaneous seizure of an RCP rotor which causes a rapid reduction in the flow through the affected RCS loop. For the accident scenario, a reactor trip occurs, SI actuates, and a LOOP occurs concurrently with the reactor trip. The flow imbalance creates localized temperature and pressure changes in the core. The radiological consequences are due to leakage of the radioactive reactor primary coolant to the SGs and from there to the environment. Because the LOOP renders the main condenser unavailable, the plant is cooled down by release of steam to the environment through ADVs and MSSVs. The releases to the environment are assumed to continue for 8 hours, at which time shutdown cooling is initiated by via operation of the RHR system. Appendix G of RG 1.183 identifies acceptable radiological analysis assumptions for an LRA and this event is described in the BVPS-1 UFSAR, Section 14.2.9, “Complete Loss of Forced Reactor Coolant Flow.”

The licensee assumed that the RCP was inoperable and loss of primary coolant circulation may result in as much as 20 percent of the core fuel rods experiencing DNB. This will cause fuel cladding damage, and release of the damaged fuel gap activity into the RCS. No fuel melting is assumed. A radial peaking factor of 1.75 was applied to the gap activity. These parameters are the current design bases in the BVPS-1 UFSAR and they are not impacted by the SG replacement or implementation of the AST. The radionuclides released from the fuel are assumed to be instantaneously and homogeneously mixed in the RCS and transported to the secondary side via primary-to-secondary leakage of 450 gpd for all three SGs for 8 hours. The licensee assumed that this leakage mixes with the bulk water of the SG’s secondary side and that the radionuclides in the bulk water become vapor at a rate that is a function of the steaming rate for the SGs and the partition coefficient.

The tubes in the SGs would remain covered by the bulk water. The licensee assumed that the radionuclide concentration in the SG is partitioned such that 1 percent of the radionuclides in the bulk water of the SGs enter the vapor space and is released to the environment consistent with guidance provided in RG 1.183. The activity releases associated with the release of secondary coolant through steaming and primary coolant through primary-to-secondary leakage and steaming at TS limits is insignificant compared to the activity in the gap release from the 20-percent damaged fuel.

The LRA event is not expected to result in an SIS. Therefore, the licensee assumed no isolation of the control room. The analyses for these events assume that the control room remains in its normal operation mode with a normal outside air intake of 500 cfm during the duration of these events (see Section 3.2, “Control Room Habitability”).
The licensee re-evaluated the radiological consequences resulting from the postulated LRA using the RSGs and concluded that the radiological consequences at the EAB, LPZ, and CR are within the dose guidelines provided in 10 CFR 50.67 and accident dose criteria specified in the SRP, Section 15.0.1. The radiological consequence of this event was performed at an EPU reactor core power level of 2918 MWt, which bounds the current licensed reactor core power level of 2689 MWt.

The NRC staff’s audit found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE and with those stated in the BVPS-1 UFSAR as design bases. The assumptions found acceptable to the NRC staff are presented in Table 6 and the licensee’s calculated dose results are given in Table 1. The NRC staff performed an independent confirmatory dose calculation to verify the licensee’s results. The EAB, LPZ, and CR doses estimated by the licensee for the LRA were found to meet the applicable accident dose criteria and are, therefore, acceptable.

4.1.4 LACP

The LACP involves the loss of AC power to plant auxiliaries. Major plant loads that would be lost include the RCP, main feedwater pump, main circulating water system, and main condenser. A reactor trip will occur. With the main condenser unavailable, the plant is cooled down by release of steam to the environment via ADVs and MSSVs. The licensee stated, and the NRC staff agrees, that the LACP event is similar to the LRA, with the exception that the LRA event results in fuel cladding damage and associated release of gap activity, whereas the LACP event involves no core fuel damage. Therefore, the radiological consequences resulting from the LRA event bounds the LACP event.

4.1.5 SLBA

The SLBA event postulates the break of a 2-inch RCS letdown line in the auxiliary building outside of the containment. The letdown line is the largest piping that carries RCS fluid outside containment. A rupture of the letdown line provides a release path for the primary coolant to the environment through the auxiliary building ventilation vent. The radiological consequence analysis of this event was performed at an EPU reactor core power level of 2918 MWt, which bounds the current licensed reactor core power level of 2689 MWt.

The licensee’s analysis assumed that no fuel failure results from the letdown line break which is consistent with the current licensing basis in BVPS-1 UFSAR. The radioactivity in the RCS was initially at the equilibrium iodine TS limit of 0.35 μCi/gm dose equivalent I-131 (DEI-131). The consideration of the equilibrium iodine TS limit of 0.35 μCi/gm DEI-131 is consistent with the review procedure provided in SRP, Section 15.6.2, "Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment." Neither RG 1.183 nor SRP 15.0.1 addresses the SLB event as a DBA.

The accident was assumed to cause the iodine concentration to spike by a factor of 500 times the equilibrium iodine appearance rate. A total of 15,110 lbm of RCS fluid was assumed released through the break, based on a break mass flow rate of 16.79 lbm per second for 15 minutes. The licensee assumed 37 percent of the break flow would flash, based on a constant enthalpy process. These parameters are consistent with the current design basis in the BVPS-1 UFSAR. Neither the implementation of the AST nor RSGs impact these parameters. Additional RCS radioactivity was assumed released to the environment through SG tube leakage and secondary system steaming to cool down the plant. The iodine activity in the break flow is assumed to be airborne in proportion to the flash fraction, whereas the noble gases are assumed to be airborne and released to the environment without decontamination or holdup.

The SLBA event is not expected to result in an SI signal. Therefore, the licensee assumed no isolation of the control room. The analyses for this event assume that the control room remains in its normal operation mode with a normal outside air intake of 500 cfm for the duration of this event (see Section 4.2 of this SE, "Control Room Habitability").

The NRC staff reviewed the information provided in the licensee's submittal and supplements and the BVPS-1 UFSAR and also performed an independent calculation that confirmed the licensee's dose results. RG 1.183 does not address an SLBA outside containment. The licensee's analysis used assumptions and inputs that follow the guidance provided for similar DBAs in RG 1.183 (LRA and CREA) and the SRP, Section 15.6.2. Since there are no specific dose acceptance criteria given in the SRP, Section 15.0.1, for the letdown line break, the licensee used the most limiting dose acceptance criteria for any DBA listed in RG 1.183 (2.5 rem TEDE in the EAB and LPZ and 5 rem TEDE in the CR). It is also consistent with the dose guideline provided in the SRP, Section 15.6.2, as a "small fraction" (i.e., 10 percent) of 10 CFR Part 100.

The NRC staff's audit found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE and with those stated in the BVPS-1 UFSAR as design bases. The assumptions found acceptable to the NRC staff are presented in Table 7 and the licensee's calculated dose results are given in Table 1. The EAB, LPZ, and CR doses estimated by the licensee for the SLBA were found to meet the applicable accident dose criteria and are, therefore, acceptable.

4.2 Control Room Habitability

The BVPS-1 control room habitability was previously evaluated and found acceptable by the NRC staff in Reference 23 for the LOCA and CREA, which would be bounding for all DBAs. However, the control room habitability evaluation is repeated here for the MSLB, SGTR, LRA, LACP, and SLBA accidents for completeness.

The BVPS-1 and 2 control rooms are located within a common control room envelope. The joint control room is served by two ventilation intakes, one for BVPS-1, and the other for BVPS-2. These air intakes are used for both the normal as well as emergency mode operations. During normal plant operation, both ventilation intakes provide a total supply of 500 cfm of unfiltered outside makeup air. For the CREA in Reference 23, and the SGTR, LRA, LACP, and SLBA in the RSG LAR, the licensee assumed that the control room is maintained in normal ventilation mode without activating the CREVS during the entire duration of these accidents. For BVPS-1 emergency power is provided to the normal control room ventilation system, including all ventilation system components that are required to support control room operation in the recirculation mode. Therefore, the NRC staff finds that it is acceptable to credit

the normal ventilation system for post-accident control room purging at the times specified in the accident analyses.

For the MSLB accident, the licensee has taken credit for operation of the CREVS and assumed manual initiation of the CREVS at 30 minutes following the accident. The CREVS pressurizes the control room. Once CREVS starts, the filtered intake flow rate is expected to vary between 600 and 1030 cfm. Sensitivity analyses by the licensee have shown that the lower flow rate is generally more limiting since the higher flow rate results in a greater dilution of control room atmosphere radioactivity concentrations. The licensee used 600 cfm CREVS flow rate in its radiological consequence analyses including the LOCA and CREA in Reference 23. The licensee assumed the control room unfiltered air inleakage of 300 cfm during the control room isolation (recirculation) mode (time the control room is isolated from 77 seconds to 30 minutes). For the emergency pressurized mode (time the control room is pressurized from 30 minutes to 30 days), the licensee assumed the control room unfiltered air inleakage of 30 cfm. The licensee based these leakage values on the result of tracer gas testing in the isolated recirculation and pressurized modes. An unfiltered inleakage of 10 cfm due to ingress and access was added to the mean values for the tracer gas measurements to arrive at the unfiltered inleakage values assumed in the dose calculations.

The licensee performed tracer gas measurements of the unfiltered inleakage to the control room in both the isolated (recirculation) and emergency pressurized modes in May of 2001, using the methodology described in American Society for Testing and Materials Standard E2029, “Standard Test Method for Volumetric and Mass Flow Rate Measurement Using Tracer Gas Dilution.” The tracer gas test results were zero cfm (no leakage) for BVPS-1 pressurization mode and 267 cfm with 10 cfm uncertainty for the recirculation mode. The NRC staff finds unfiltered air inleakage values assumed by the licensee to be acceptable based on tracer gas testing results. The CREVS intake filters are assumed to be 99 percent efficient for particulates and 98 percent efficient for elemental and organic iodine species. The BVPS-1 control room unfiltered air inleakage values and CREVS filter efficiencies were previously accepted by the NRC staff in Reference 23.

4.3 Atmospheric Dispersion

The licensee generated new atmospheric dispersion factors (χ/Q values) using the NRC-sponsored ARCON96 computer code (NUREG/CR-6331, Revision 1, “Atmospheric Relative Concentrations in Building Wakes”) to evaluate the impact of the BVPS-1 and 2 ventilation vent and BVPS-1 MSLB point releases on the BVPS-1 and 2 control rooms. These χ/Q values represent a change from the χ/Q values used in the current BVPS-1 and 2 UFSAR, Chapter 14, accident analysis. The licensee used previously approved χ/Q values to assess the dose for a postulated release from the main steamline relief valves to the BVPS-1 and 2 air intakes and to perform dose assessments for the BVPS EAB and LPZ. Although this amendment request is for BVPS-1, the licensee compared the χ/Q values for BVPS-1 and 2 and used the more limiting control room, EAB and LPZ χ/Q values in each dose assessment associated with the RSG LAR.

4.3.1 Meteorological Data

The licensee generated new control room χ/Q values for postulated releases from the BVPS-1 and 2 ventilation vents and BVPS-1 MSLB point using site meteorological data collected from 1990–1994. The licensee previously provided these data and the NRC staff reviewed and discussed these data in the SE associated with BVPS-1 and 2, Reference 23. Based on the meteorological measurements program and meteorological database review described in the SE associated with Reference 23, the NRC staff has concluded that the 1990–1994 site meteorological database provides an acceptable basis for making atmospheric dispersion estimates for use in support of the RSG LAR.

4.3.2 Control Room Atmospheric Dispersion Factors

The licensee calculated new control room χ/Q values for one new release point, the southeast corner of the turbine building for the MSL break dose assessment, and revised control room χ/Q values for the BVPS-1 and 2 ventilation vents. These new and revised control room χ/Q values were calculated using the ARCON96 computer code and guidance provided in RG 1.194, “Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants.” The licensee executed ARCON96 using the 1990–1994 onsite hourly 10.7-meter and 45.7-meter wind data and stability class determined from the temperature difference measured between the 45.7-meter and 10.7-meter levels. All releases were modeled as point sources using the ARCON96 ground-level release mode option. The NRC staff evaluated the applicability of the ARCON96 model and concluded that there are no unusual siting, building arrangements, release characterization, source-receptor configuration, meteorological regimes, or terrain conditions that preclude use of the ARCON96 model for the BVPS site. The NRC staff qualitatively reviewed the inputs to the ARCON96 calculations and found them generally consistent with site configuration drawings and NRC staff practice. In addition, the NRC staff performed a check of the resulting atmospheric dispersion estimates by running the ARCON96 computer code and obtained similar results.

The licensee used previously approved χ/Q values for the control room dose assessment for postulated releases from the main steamline relief valves. These χ/Q values are discussed in the SE associated with Reference 23.

For the reasons cited above, the NRC staff has concluded that the control room χ/Q values presented in Table 2 are acceptable for use in the DBA assessments described in this SE. For all release pathways, postulated releases from BVPS-1 to the BVPS-1 control room air intake were the most limiting cases.

4.3.3 EAB and LPZ Atmospheric Dispersion Factors

The licensee used existing χ/Q values that were accepted by the NRC staff in a previous licensing proceeding to evaluate the impact of the BVPS-1 and 2 postulated releases to the EAB and LPZ. Although this amendment request is for BVPS-1, the licensee compared the EAB and LPZ χ/Q values for BVPS-1 and 2 and used the more limiting χ/Q values in the dose assessment discussed above. Based on the review described in the SE associated with Reference 23 and a review of the licensee's use of these χ/Q values in the RSG LAR, the NRC

staff has concluded that the EAB and LPZ χ/Q values presented in Table 3 are acceptable for use in the DBA assessments described in this SE.

4.4 Conclusion

As described above, the NRC staff reviewed and audited the assumptions, inputs, and methods used by the licensee to assess the radiological consequences for the SG replacement with expanded selective implementation of an AST at BVPS-1. The NRC staff finds that the licensee used analysis methods and assumptions consistent with the conservative regulatory requirements and guidance identified in Section 2.0 above. The NRC staff compared the doses estimated by the licensee to the applicable criteria identified in Section 2.0. The NRC staff also finds, with reasonable assurance, that the licensee's estimates of the EAB, LPZ, and CR doses will comply with these criteria. The NRC staff further finds reasonable assurance that BVPS-1, as modified by this license amendment, will continue to provide sufficient safety margins with adequate defense-in-depth to address unanticipated events and to compensate for uncertainties in accident progression and analysis assumptions and parameters. Therefore, the proposed RSG LAR is acceptable.

This licensing action is considered an expanded selective implementation of the AST. With this approval, the previous accident source term in the BVPS-1 design basis is superseded by the AST proposed by the licensee. The previous offsite and control room accident dose criteria expressed in terms of whole body, thyroid, and skin doses are superseded by the TEDE criteria of 10 CFR Part 50.67, or fractions thereof, as defined in SRP, Section 15.0.1. All future radiological accident analyses performed to show compliance with regulatory requirements shall address all characteristics of the AST and the TEDE criteria as defined the BVPS-1 design basis, and as modified by this license amendment.

Table 1
Radiological Consequences Expressed as TEDE [(1)]
(rem)

Design Basis Accidents	EAB [(2)]	LPZ [(3)]	Control Room
MSLB accident [(4)]	8.0E-2	1.0E-2	5.0E-1
Dose criteria	25	25	5.0
MSLB accident [(5)]	1.1E-1	4.0E-2	6.6E-1
Dose criteria	2.5	2.5	5.0
SGTR [(4)]	2.27	1.4E-1	1.95
Dose criteria	25	25	5.0
SGTR [(5)]	9.3E-1	6.0E-2	0.67
Dose criteria	2.5	2.5	5.0
LRA	2.0	3.3E-1	2.2
Dose criteria	2.5	2.5	5.0
SLBA	2.3E-1	1.2E-2	7.0E-1
Dose criteria	2.5	2.5	5.0

(1) Total effective dose equivalent
(2) Exclusion area boundary
(3) Low population zone
(4) Pre-accident initiated iodine spike
(5) Accident iodine spike

Table 2

<u>BVPS-1</u>
<u>Control Room Atmospheric Dispersion Factors (sec/m^3)</u>

Accident: MSLB and SGTR to BVPS-1 Control Room Intake

Time Interval (hrs)	MSSVs/ADVs (BVPS-1 MS Relief Valves)	Main Steam Line Break Point (BVPS-1 Turbine Building)
0 – 2	1.24×10^{-3}	1.05×10^{-2}
2 – 8	9.94×10^{-4}	7.72×10^{-3}
8 – 24	4.08×10^{-4}	3.01×10^{-3}
24 – 96	3.03×10^{-4}	2.14×10^{-3}
96 – 720	2.51×10^{-4}	2.00×10^{-3}

Accidents: LRA, LACP, and SLBA to BVPS-1 Control Room Intake

Time Interval (hrs)	LRA and LACP (BVPS-1 MS Relief Valves)	SLB (BVPS-1 Ventilation Vent)
0 – 2	1.24×10^{-3}	4.75×10^{-3}
2 – 8	9.94×10^{-4}	3.66×10^{-3}
8 – 24	4.08×10^{-4}	1.43×10^{-3}
24 – 96	3.03×10^{-4}	1.02×10^{-3}
96 – 720	2.51×10^{-4}	8.84×10^{-4}

Table 3

BVPS EAB Atmospheric Dispersion Factors (sec/m^3)
(0 to 2 hrs)

BVPS-1	1.04×10^{-3} (Note 1)
BVPS-2	1.25×10^{-3}

Note 1: The more conservative Unit 2 χ/Q value was used for the LRA, LACP, and SLB events.

BVPS-1 LPZ Atmospheric Dispersion Factors

Time Interval (hrs)	χ/Q Values (sec/m^3)
0 to 8	6.04×10^{-5}
8 to 24	4.33×10^{-5}
24 to 96	2.10×10^{-5}
96 to 720	7.44×10^{-6}

Table 4
Parameters and Assumptions Used in Radiological Consequence Calculations for the MSLB Accident

Parameter	Value
Core Power Level	2918MWt
Pre-incident iodine spike activity	21 μCi/gm dose equivalent I-131
Co-incident spike appearance rate multiplier	500
Iodine spike duration, hrs	4
Primary-to-secondary leakage per SG, gpd	150
Duration, hours	
Faulted SG	19
Intact SG	8
Liquid Masses, lbm	
RCS	3.4E+5
SG (each)	1.0E+5
Steam release from intact SGs, lbm	
0 to 2 hours	3.45E+5
2 to 8 hours	7.34E+5
Steam iodine partition coefficient in SGs	
Faulted SG	1.0
Intact SG	100
Release points	
Faulted SG	Break point
Intact SG	ADVs and MSSVs

Table 5
Parameters and Assumptions Used in Radiological Consequence Calculations for the SGTR Accident

Parameter	Value
Core Power Level	2918MWt
Pre-incident iodine spike activity	21 µCi/gm dose equivalent I-131
Co-incident spike appearance rate multiplier	335
Iodine spike duration, hrs	4
Primary-to-secondary leakage per SG, gpd	150
Duration, hours	8
Liquid Masses, lbm	
RCS	3.7E+5
SG (initial mass per SG)	9.6E+4
Steam release from faulted SG, lbm	
225 seconds to 0.5 hours	6.89E+4 lbm (flashed)
Steam release from intact SGs, lbm	
225 seconds to 2 hours	4.17E+5
2 to 8 hours	9.795E+5
Steam iodine partition coefficient in SGs	
Faulted SG	1.0
Unaffected SG	100
Release points	MSSVs and ADVs atmospheric relief valves

Table 6
Parameters and Assumptions Used in Radiological Consequence Calculations for the LRA and LACP Accidents

Parameter	Value	
Core Power Level	2918 MWt	
Fraction of failed fuel	0.2	
Fraction of Core Inventory in Gap		
Kr-85	0.10	
I-131	0.08	
Alkali metals	0.12	
Other noble gases / iodines	0.05	
Iodine speciation	CNMT	Secondary
Aerosol	0.95	0
Elemental	0.0485	0.97
Organic	0.0015	0.3
Primary to secondary leakage per SG, gpd	150	
Primary to secondary leakage duration, hours	8	
Steam partition coefficient in SGs	100	
Steam release from all 3 SGs, lbm		
0 to 2 hours	3.48E+5	
2 to 8 hours	7.78E+5	
Release points	MSSVs and ADVs	

Table 7
Parameters and Assumptions Used in Radiological Consequence Calculations for the SLBA

Parameter	Value
Core power level	2918 MWt
Letdown line mass flow rate	16.79 lbm per second
Break flow flash Fraction	37 percent
Break isolation time	15 minutes
Melted fuel	none
Failed fuel	none
RCS equilibrium iodine activity	0.35 μCi/gm dose equivalent I-131
Co-incident spike appearance rate multiplier	500
Iodine spike duration, hrs	4
Release points	ventilation vent

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Pennsylvania State official was notified of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts and no significant change in the types of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (70 FR 35737). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

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Date: February 9, 2006

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