Table of Contents

Safety Evaluation Related to Extended Power Uprate at

Beaver Valley Power Station, Unit Nos. 1 And 2

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NOS. 275 AND 156 TO FACILITY OPERATING

LICENSE NOS. DPR-66 AND NPF-73

FIRSTENERGY NUCLEAR OPERATING COMPANY

FIRSTENERGY NUCLEAR GENERATION CORP.

OHIO EDISON COMPANY

THE TOLEDO EDISON COMPANY

BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 (BVPS-1 AND 2)

DOCKET NOS. 50-334 AND 50-412

1.0 INTRODUCTION

1.1 Application

By license amendment request (LAR) dated October 4, 2004, as supplemented by letters dated February 23, May 26, June 14, July 8 and 28, August 26, September 6, October 7, 28, and 31, November 8, 18, and 21, December 2, 6, 9, 16, and 30, 2005, and January 25, February 14 and 22, March 10 and 29, May 12, and July 6, 2006 (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML042920300, ML051160426, ML051160429, ML051160431, ML051530376, ML051670270, ML051940575, ML051940582, ML051940583, ML052140310, ML052430345, ML052550373, ML052850145, ML053050300, ML053110142, ML053180264, ML053290133, ML053290135, ML053290139, ML053290140, ML053420435, ML053420440, ML053460239, ML053490152, ML053560175, ML060040166, ML060330262, ML060520569, ML060590252, ML060750572, ML060930559, ML061360075, and ML061910053, respectively), FirstEnergy Nuclear Operating Company (FENOC, the licensee) requested changes to the Facility Operating Licenses and Technical Specifications (TSs) for the Beaver Valley Power Station, Unit Nos. 1 and 2 (BVPS-1 and 2). The supplemental letters dated February 23, May 26, June 14, July 8 and 28, August 26, September 6, October 7, 28, and 31, November 8, 18, and 21, December 2, 6, 9, 16, and 30, 2005, and January 25, February 14 and 22, March 10 and 29, May 12, and July 6, 2006, provided additional clarifying information that did not expand the scope of the initial application as published in the *Federal Register* on August 17, 2005 (70 FR 48443).

Enclosure

The proposed changes would increase the maximum steady-state reactor core power level from 2689 megawatts thermal (MWt) to 2900 MWt, which is an increase of approximately 8 percent. The proposed increase in power level is considered an extended power uprate (EPU).

1.2 Background

1.2.1 General Design Features

BVPS-1 and 2 are pressurized-water reactors (PWRs) of the Westinghouse 3-Loop design each with a vertical, cylindrical steel-lined, reinforced concrete containment with a hemispherical dome and flat base.

The BVPS site is located on the southern shore of the Ohio River in the Borough of Shippingport in Beaver County, Pennsylvania, about 25 miles northwest of Pittsburgh, Pennsylvania, one mile southeast of Midland, Pennsylvania, 8 miles east of Newell, West Virginia, 6 miles southwest of Beaver, Pennsylvania, and 5 miles east of East Liverpool, Ohio. The area is primarily industrial with some agricultural activity. The low population zone area distance is 3.6 miles. The population center distance is 17 miles.

1.2.2 Shared Systems, Structures, and Components/Unique Design Features

BVPS-1 and 2 have the following shared structures, systems and components and special features/unique designs:

1.2.2.1 Intake Structure

The seismic Category I intake structure is a structure common to both BVPS-1 and 2. The BVPS-1 river water pumps and the BVPS-2 service water pumps housed in this structure are considered essential systems and are so designed. Both the river water and service water systems are operated completely independent of each other and are designed to meet single failure criteria. A cross-connect is provided between one of the two river water and one of the two service water discharge headers. This cross-connect is usually inoperable and is isolated from the two headers by two isolation valves. Catastrophic failure of one river water or service water pump can disable the other pump located in the same bay. However, since three 100% capacity pumps are provided for the river water and the service water systems and there is a cross-connect available, there is no credible way that failure of one system can disable the other. The possibility of other essential and nonessential equipment failures damaging the essential river water and service water piping and pumps is not considered credible.

1.2.2.2 Main Control Area

The control areas for BVPS-1 and 2 are located in the same seismic Category I missile-protected structure. However, the control boards for the individual units are physically and functionally separated within the common main control area.

1.2.2.3 Station Blackout 4160 V Cross-Tie

A cross-tie connecting the 4160 v normal busses 1A, 1D, 2A, and 2D of BVPS-1 and 2 provides the capability to power either of the emergency busses at one unit from either of the emergency diesel generators (EDGs) at the other unit.

1.2.3 Associated TS Amendments

1.2.3.1 Steam Generator (SG) Level Allowable Value (AV) Setpoint Changes

Amendment No. 270 to Facility Operating License No. DPR-66 and Amendment No. 152 to Facility Operating License No. NPF-73 for BVPS-1 and 2 were issued on January 11, 2006, and consisted of changes to the TSs in response to the application dated October 5, 2004, as supplemented March 22, August 29, and October 31, 2005. These amendments revised the BVPS-1 and 2 TSs 3/4.3.1, "Reactor Trip System Instrumentation," and 3/4.3.2, "Engineered Safety Feature Actuation Instrumentation," to modify SG level AV setpoints. Specifically, the TS changes increased the AVs of the SG water level-low-low setpoints from 14.6 percent and 16 percent to 19.6 percent and 20 percent of the narrow range (NR) instrument span for BVPS-1 and 2, respectively. These are the AVs of setpoints specified in TS Table 3.3-1 to initiate a reactor trip, and the actuation setpoints specified in TS Table 3.3-3 to start the auxiliary feedwater pumps. Also, for BVPS-2, the AV of the SG water level-high-high setpoint increased from 81.1 percent to 92.7 percent of the NR span. This is the AV of a setpoint for actuation of the turbine trip and the feedwater system isolation specified in TS Table 3.3-3. These changes addressed recent generic issues involving SG water level measurement uncertainty considerations associated with Westinghouse-designed SGs.

1.2.3.2 Containment Conversion From Subatmospheric to Atmospheric Operating Conditions

Amendment No. 271 to Facility Operating License No. DPR-66 and Amendment No.153 to Facility Operating License No. NPF-73 for BVPS-1 and 2 were issued on February 6, 2006, and consisted of changes to the TSs in response to the licensee's application dated June 2, 2004, as supplemented February 11, May 12, October 31, and November 14, 2005. These amendments approved conversion of the BVPS-1 and 2 containments from subatmospheric to atmospheric operating conditions and also approved the Modular Accident Analysis Program - Design-Basis Accident (MAAP-DBA) computer code for the BVPS-1 and 2 containment integrity analysis and changes to mass and energy calculation methodologies.

1.2.3.3 Best-Estimate Loss-Of-Coolant Accident (BELOCA)

Amendment No. 272 to Facility Operating License No. DPR-66 and Amendment No. 154 to Facility Operating License No. NPF-73 for BVPS-1 and 2 were issued on February 6, 2006, and consisted of changes to the TSs in response to the licensee's application dated October 4, 2004, as supplemented July 8, and November 14, 2005.

The changes approved application of the Nuclear Regulatory Commission (NRC)-approved Westinghouse BELOCA analysis methodology described in Topical Report WCAP-12945-P-A, Volume 1 (Revision 2) 1996 and Volumes 2 through 5 (Revision 1), "Code Qualification Document [CQD] for Best Estimate LOCA Analysis, March 1998," (CQD methodology) for BVPS-1 and 2. The NRC has approved the CQD methodology for performing licensing basis large-break LOCA (LBLOCA) analyses for all 3- and 4-loop nuclear plants of Westinghouse design.

1.2.3.4 BVPS-1 SG Replacement

Amendment No. 273 to Facility Operating License No. DPR-66 for BVPS-1 was issued on February 9, 2006, and consisted of changes to the TSs in response to the licensee's 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 revised the TSs to allow replacement of the BVPS-1 SGs. These changes included revision of the fuel assembly-specific departure from nucleate boiling ratios and correlations, modification of the Overtemperature ΔT and Overpower ΔT equations, revision of the SG water level low-low and high-high setpoints, revision of the SG secondary side level in Modes 4 and 5, revision of the SG TSs to reflect the replacement SGs and removal of TS requirements that are not applicable to the new SGs, revision of the required charging pump discharge pressure for reactor coolant pump seal injection flow, a raise of the accumulator pressure, and addition of 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 approved an expanded selective alternate source term methodology implementation in accordance with Regulatory Guide (RG) 1.183, "Alternative 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 (MSLB) outside containment.

1.2.3.5 Revised Axial Offset Control (RAOC)

Amendment No. 274 to Facility Operating License No. DPR-66 and Amendment No. 155 to Facility Operating License No. NPF-73 for BVPS-1 and 2 issued on February 27, 2006, consisted of changes to the TSs in response to the licensee's application dated February 11, 2005, as supplemented August 8, 2005.

These amendments approved the adoption of the RAOC and F_Q surveillance methodologies in accordance with NRC-approved Topical Report WCAP-10216-P-A, "Relaxation of Constant Axial Offset Control F_Q Surveillance Technical Specification." TS 3.2.1, "Axial Flux Difference (AFD)," and TS 3.2.2, "Heat Flux Hot Channel Factor - $F_Q(z)$," were revised to adopt the RAOC calculational procedure of NUREG-1431, "Standard Westinghouse Technical Specifications for Westinghouse Plants, Revision 3, June 2004." Changes to TS 3.2.3, "Nuclear Enthalpy Hot Channel Factor - $F^N_{\Delta H}$," TS 3.2.4, "Quadrant Power Tilt Ratio (QPTR)," TS 3.3.1, "Reactor Trip System Instrumentation (Table 4.3-1, Note 3)," and TS 6.9.5, "Core Operating Limits Report (COLR)," have been made to provide consistency with the changes made to TSs 3.2.1 and 3.2.2.

1.3 Licensee's Approach to EPU

The licensee's application for the proposed EPU follows the guidance in the Office of Nuclear Reactor Regulation's (NRR's) Review Standard (RS)-001, "Review Standard for Extended Power Uprates," Revision 0, December 2003 [1], to the extent that the RS is consistent with the design basis of the plant. Where differences exist between the plant-specific design basis and RS-001, the licensee described the differences and provided evaluations consistent with the design basis of the plant. As part of its October 4, 2004, application, the licensee included as Enclosure 2, the "Beaver Valley Power Station Extended Power Uprate Licensing Report,"

September 2004 (hereafter referred to as the EPULR). As Enclosure 4, the licensee included Westinghouse Topical Reports, WCAP-6307-P (proprietary version), and WCAP-16307-NP (non-proprietary version), “Beaver Valley Units 1 and 2 Extended Power Uprate Licensing Report Supplemental Information,” September 2004, and as Enclosure 5, the licensee included Westinghouse Topical Reports, WCAP-13483-P, Revision 2 (proprietary version), and WCAP-13484-NP, Revision 2 (non-proprietary version), “Beaver Valley Units 1 and 2 Westinghouse Series 51 Steam Generator Sleeving Report - Laser Welded Sleeves,” Revision 2, October 2002. The licensee provided supporting analyses for its request for full implementation of an alternative source term methodology in accordance with RG 1.183, and performed supporting EPU analyses based, in part, on the NRC-approved BELOCA methodology described in Topical Report WCAP-12945-P-A, Volume 1, Revision 2, 1996 and Volumes 2 through 5, Revision 1, March 1998 (CQD methodology).

In early 2000, the licensee implemented a Full Potential Program for BVPS-1 and 2. The program included a measurement uncertainty recapture power uprate and a larger power uprate to maximize the Nuclear Steam Supply Systems (NSSS) power level and value of the BVPS. The Full Potential Program also included implementing a SG preventive maintenance program at BVPS-1 to support postponing SG replacement until optimal, and replacing SGs at BVPS-1 when it was most advantageous (spring 2006 refueling outage). The initial measurement uncertainty power uprate was requested in early 2001, approved by the NRC in mid-2001 and implemented by the licensee in fall 2001 for BVPS-1 and 2. The reactor power was increased from an initial value of 2652 MWt to 2689 MWt for an increase of 1.4 percent.

The larger power uprate project was initiated in mid-2000 and included an initial scoping review to select the power level to which BVPS-1 and 2 would be uprated. The initial step of the scoping review was to review the original BVPS-1 and 2 designs and current power levels of comparable 3-loop plants. Table 1.0-1 in the licensing report summarizes the results of the licensee’s review. Based on the reviews of power uprates for the Joseph M. Farley Nuclear Plant, the Virgil C. Summer Nuclear Station, Unit No. 1, and the Shearon Harris Nuclear Power Plant, Unit 1, the licensee selected 2 power levels for the scoping evaluation, 2803 MWt (equivalent to a stretch power uprate) and 2900 MWt (EPU). The results of the scoping review showed that the NSSS could support either power level with comparable impacts on NSSS safety systems, NSSS components, accident analyses and nuclear fuel. The balance-of-plant (BOP) could support an increase to 2803 MWt with minimal impact to BOP systems and components, but additional modifications to BOP systems and components would be needed to support an increase to 2900 MWt. The turbine generator would need to be modified for either power level increase (the extent of the modifications were comparable regardless of which power level increase was selected). Based on the scoping review results, the licensee selected the proposed uprated power level for BVPS-1 and 2. The increase in reactor power (rated thermal power or RTP) to 2900 MWt constitutes a 9.4 percent increase relative to the original licensed power level of 2652 MWt but approximately an 8 percent increase relative to the current licensed power level of 2689 MWt.

The licensee plans a staged implementation of the EPU. Each stage will be implemented as the required modifications are completed which enable the units to produce the increased electrical output. Following the NRC-approval of the EPU LAR, the licensee plans to complete the implementation of safety-related equipment modifications and TS changes and incorporate the EPU analyses as the analysis-of-record (AOR) for BVPS-1 and 2. The licensee will continue operating at the current power level until the required non safety-related BOP

equipment modifications are implemented (except for the BVPS-2 high pressure (HP) turbine modifications). The licensee completed its BVPS-1 outage-related modifications necessary to support the EPU during the spring 2006 refueling outage and plans to make the outage-related modifications necessary to support the EPU during the fall 2006 refueling outage for BVPS-2, except for BVPS-2 HP turbine modifications (required for full EPU implementation) which will be completed at a later outage (currently scheduled for the spring 2008 outage).

1.4 Plant Modifications

The principal modifications planned to support implementation of the BVPS-1 and 2 EPU analyses include:

1. Containment conversion from subatmospheric to atmospheric operating conditions including related modifications such as the addition of feedwater isolation valves and auxiliary feedwater (AFW) flow limiting venturis for BVPS-1.

2. Replacement charging/safety injection (SI) pump rotating assemblies.

3. Replacement steam generators (RSGs) for BVPS-1.

The principal BOP modifications planned to support operation at higher power level include:

1. BOP replacement HP all-reaction turbines.

2. BOP electrical transformer modifications for BVPS-2.

3. BOP main condenser modifications for BVPS-2.

4. BOP cooling tower modifications for BVPS-2.

5. BOP moisture separator reheater (MSR) relief valve modifications.

6. BOP main feedwater control valve (FCV) trim modifications.

7. BOP heater drain control valve modifications.

8. BOP instrument replacements.

The NRC staff's evaluation of the licensee's proposed plant modifications is provided in Section 2.0 of this safety evaluation (SE).

1.5 Method of NRC Staff Review

The NRC staff reviewed the licensee's application to ensure 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) activities proposed will be conducted in compliance with the

Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

The NRC staff evaluated the licensee's application and supplements. The NRC staff's evaluation included an audit of Westinghouse calculations, upon which certain accident analyses, presented in the uprating application, were based. The staff focused upon event analyses that are (1) sensitive to the plant's uprated conditions, and (2) analyzed with methods that have not been heretofore applied in the BVPS-1 and 2 dockets. Specifically, several NRC staff members visited Westinghouse's offices in Monroeville, Pennsylvania, on November 7-9, 2005, and audited calculations that supported most of the licensee's analyses, including the small-break loss-of-coolant accident (SBLOCA), the MSLB, feedwater line break, and loss-of-feedwater analyses. At the staff's request, Westinghouse made available copies of these calculations, and its internal analysis guidelines, for use by the staff, at their liaison office in Rockville, Maryland. These documents are subject to applicable proprietary-information withholding controls. In addition, Westinghouse permitted members of the NRC staff to access and use the LOFTRAN code, including applicable input data, for the purpose of making confirmatory calculations and performing sensitivity studies. Most of the non-LOCA accident analyses, reported in BVPS-1 and 2 LAR, are based upon the results of LOFTRAN simulations. LOFTRAN is a whole-plant simulation code that has been accepted by the NRC staff for licensing applications. The NRC staff also performed independent calculations related to the SBLOCA, and long-term cooling (boron precipitation) analyses.

The NRC staff also performed audits at the BVPS site on October 18 and 19, 2005, to assess the licensee's probabilistic risk assessment models, and on November 29 and 30, 2005, to review the design-based accident dose calculations.

In areas where the licensee and its contractors used NRC-approved methods in performing analyses related to the proposed EPU, the NRC staff reviewed relevant material to ensure that the licensee/contractor used the methods consistent with the limitations and restrictions placed on the methods. In addition, the NRC staff considered the effects of the changes in plant operating conditions on the use of these methods to ensure that the methods are appropriate for use at the proposed EPU conditions. Details of the NRC staff's review are provided in Section 2.0 of this SE.

2.0 EVALUATION

2.1 Materials and Chemical Engineering

For BVPS-1, the expiration of the current operating license (EOL) is projected to occur at 28 effective full-power years (EFPY). Table 4.1.2-1A of the EPULR indicates that the power uprate will reduce the projected EFPY for EOL from 27.58 EFPY to 27.44 EFPY, as based on the neutron fluences that are reported in WCAP-15570, "Beaver Valley Unit 1 Heatup and Cooldown Curves for Normal Operation," April 2001, for the clad-to-base metal interface.

The 27.44 EFPY value associated with EOL for BVPS-1 accounts for the need to modify the neutron dosimetry calculations for BVPS-1, as specified in WCAP-15571, Revision 0, "Analysis of Capsule Y from Beaver Valley Unit 1 Reactor Vessel Radiation Surveillance Program," November 2000, to account for the 8-percent RTP increase proposed in the EPULR. For BVPS-1, the limiting neutron fluence for the clad-to-base metal interface location of the reactor

vessel (RV) at EOL is 3.54×10^{19} n/cm^2 (E > 1.0 MeV). The NRC staff's basis for approving this neutron fluence value is given in Section 2.8.4.3 of this SE.

Table 4.1.2-1B of the EPULR indicates that EOL for BVPS-2 is projected to occur at 32 EFPY. The EPU does not impact the projected EOL for BVPS-2 because the neutron fluence dosimetry calculations for the RV, as specified in WCAP-15675, "Analysis of Capsule W from FirstEnergy Nuclear Operating Company Beaver Valley Unit 2 Reactor Vessel Radiation Surveillance Program," August 2001, are derived on EPU-based neutron fluence data. For BVPS-2, the limiting neutron fluence at EOL for the clad-to-base metal interface location of the RV is 3.85×10^{19} n/cm^2 (E > 1.0 MeV). The NRC staff's basis for approving this neutron fluence value is given in Section 2.8.4.3 of this SE.

In the licensee's supplement of May 12, 2006 [70], the licensee amended the EPU LAR and revised the EFPY values associated with the EOL dates for BVPS-1 and 2. In this supplement, the licensee indicated that the amended EFPY values for at EOL for BVPS-1 and 2 are 30.52 EFPY and 36 EFPY, respectively.

For BVPS-1 and 2, the increases in the EPU-based EOL EFPY values (i.e., from 27.44 EFPY to 30.52 EFPY for BVPS-1 and from 32 EFPY to 36 EFPY for BVPS-2) are based on two factors: (1) removal of the licensee-implemented but non-mandatory conservatism that the 8-percent increase in RTP commenced in 2003, and (2) achievement of an approximately 98-percent capacity factor for operating cycles 16 and 17 for BVPS-1 and operating cycles 10 and 11 for BVPS-2 and projected future capacity factors of 98 percent with an average 22-day refueling outage for each unit. These factors do not impact the licensee's projected, limiting EOL fluence values for BVPS-1 and 2 RVs.

For BVPS-1, the calculated values for the EOL fluence which were calculated in the EPULR assumed that a 1.4-percent MUR uprate was implemented in June 2001 and an approximate 8-percent EPU was implemented in June 2003. In actuality, the 8-percent EPU will not be implemented until August 2006 or later. The recapture of the overestimation of fluence resulting from the delayed implementation of the 8-percent EPU is offset by the increased fluence resulting from the higher current and projected capacity factors. However, WCAP-15571, which includes the calculated values with the original assumptions, indicates a peak vessel-clad interface fluence of 3.54×10^{19} n/cm^2. The licensee's May 12, 2006, supplement [77] using the WCAP 15571 results while adjusting for the increased load factors and delayed EPU implementation, and maintaining the same low leakage core load conditions (L4P) results in the same peak vessel fluence of 3.54×10^{19} n/cm^2. The methodology in WCAP-15571 adheres to the guidance in RG 1.190, therefore, the 3.54×10^{19} n/cm^{2}value is acceptable.

For BVPS-2,WCAP-16527 calculates the fluences and accounted for the loading pattern (L4P) that is being maintained, the 1.4-percent MUR uprate implementation and the actual projected EPU uprate implementation date. The peak vessel fluence calculated at EOL is 4.11×10^{19} n/cm^2. The methodology in WCAP-16527 adheres to the guidance of RG 1.190, therefore, the calculated fluence value of 4.11×10^{19} n/cm^2 is acceptable.

2.1.1 Reactor Vessel Material Surveillance Program

<u>Regulatory Evaluation</u>

The reactor vessel material surveillance program (henceforth abbreviated RVMSP) provides a means for determining and monitoring the fracture toughness of the RV beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the RV. Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix H, provides the NRC staff's requirements for the design and implementation of the RVMSP. The staff's review primarily focused on the effects of the proposed EPU on the licensee's RV surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on (1) General Design Criterion (GDC) 14, which requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture; (2) GDC 31, which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the RV beltline region; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria are contained in Standard Review Plan (SRP), Section 5.3.1, and other guidance provided in Matrix 1 of NRC Review Standard, RS-001.

Technical Evaluation

Appendix H to 10 CFR Part 50, invokes, by reference, the guidance in American Society for Testing and Materials (ASTM) Standard Practice E185, "Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." The ASTM Standard Practice provides guidelines for designing and implementing the RVMSPs for operating light-water reactors, including guidelines for establishing RV surveillance capsule withdrawal schedules. With respect to these schedules, Appendix H to 10 CFR Part 50 requires licensees to apply the version of the ASTM standard that was current on the issue date of the American Society for Mechanical Engineers *Boiler and Pressure Vessel Code* (ASME Code) to which the RV was purchased. The rule permits more current versions of ASTM E185 to be used for the withdrawal schedule but only through versions inclusive of the 1982 edition of the standard (henceforth referred to as ASTM E185-82). FENOC is applying ASTM E185-82 as its basis for implementing both the BVPS-1 and BVPS-2 RVMSPs. Appendix H to 10 CFR Part 50 also requires that technical summary reports on RV surveillance capsule testing be submitted to the NRC within 1 year of the surveillance capsule withdrawals.

ASTM E185-82 requires that either three, four, or five surveillance capsules be removed from a RV, depending on whether the limiting EOL shift in RT_{NDT} (i.e., ΔRT_{NDT} values) for the RV is either less than or equal to 100 EF, between 100 EF and 200 EF, or greater than 200 EF. Table 2.1.1-1 (below) summarizes what the withdrawal time requirements are for three, four, or five capsule programs that are implemented in accordance with the ASTM standard.

Table 2.1.1-1 Summary of ASTM E185-82 Requirements for RV Surveillance Capsule Withdrawal Schedules, as Invoked by 10 CFR Part 50, Appendix H

Designated Capsule in Withdrawal Schedule Sequence	Time of Withdrawal for a Required Three Capsule Withdrawal Schedule	Time of Withdrawal for a Required Four Capsule Withdrawal Schedule	Time of Withdrawal for a Required Five Capsule Withdrawal Schedule

	Predicted ΔRT_{NDT} # 100EF	100EF < Predicted ΔRT_{NDT} # 200EF	Predicted ΔRT_{NDT} > 200EF
1st	6 EFPY [a]	3 EFPY [a]	1.5 EFPY [a]
2nd	15 EFPY [d]	6 EFPY [©]	3 EFPY [b]
3rd	EOL [e]	15 EFPY [d]	6 EFPY [©]
4th	---	EOL [e]	15 EFPY [d]
5th	---	---	EOL [e]

Abbreviations:

1. EF - degrees Fahrenheit, which is a unit of temperature in the English System of weights and measures.
2. EFPY - effective full power years, which represents the accumulated time in years when operating at full power capacity.
3. ΔRT_{NDT} - Limiting Shift in Adjusted Reference Transition Temperature projected for the inside surface of the RV.
4. EOL - end of licensed operating life.

Footnotes:

(a) Or at the time when the accumulated neutron fluence of the capsule exceeds $5x10^{18}$ n/cm^2 (E $ 1.0 MeV), or at the time when the highest predicted ΔRT_{NDT} of all encapsulated materials is approximately 50 EF (28 EC), whichever comes first.

(b) Or at the time when the accumulated neutron fluence of the capsule corresponds to a value midway between that of the first and third capsules.

©) Or at the time when the accumulated neutron fluence of the capsule corresponds to the approximate EOL fluence at the RV 1/4T location, whichever comes first.

(d) Or at the time when the accumulated neutron fluence of the capsule corresponds to the approximate EOL fluence at the inner wall location, whichever comes first.

(e) At a time when the capsule achieves a neutron fluence of not less than once or greater than twice the peak RV fluence at the inner surface location of the RV.

Impact of the 8-percent EPU on the BVPS-1 RV Surveillance Capsule Withdrawal Schedule

The current docketed version of the surveillance capsule withdrawal schedule for the BVPS-1 RVMSP is given in Table 7-1 of WCAP-15571, Revision 0, “Analysis of Capsule Y from the Beaver Valley Unit 1 Reactor Vessel Radiation Surveillance Program.” Table 4.1.2-2A of the EPULR resubmitted the same surveillance capsule withdrawal schedule that was proposed in Table 7-1 of WCAP-15571, Revision 0, with the exception that Table 4.1.2-2A made some minor adjustments of withdrawal time and neutron fluence value for the projected withdrawal of BVPS-1 Capsule X.

In its March 11, 2005, request for additional information (RAI) J.8, the NRC staff inquired whether the licensee was requesting review and approval of the new RV surveillance capsule withdrawal schedule that was provided in Table 4.1.2-2A of the EPULR. RAI J.8 is relevant to determining whether the new withdrawal schedule in Table 4.1.2-2A of the EPULR had been reviewed and approved by the staff, as required pursuant to Section III.B.3 of 10 CFR Part 50, Appendix H.

In its response to RAI No. J.8 [9], the licensee stated that the impact of the EPU on the RV surveillance capsule withdrawal for BVPS-1 is adequately addressed in Section 4.1.2 of the

EPULR. In its supplemental response to RAI J.8, the licensee confirmed that the previous withdrawal schedule for BVPS-1, as provided in WCAP-15571, Revision 0, was approved in an SE to FENOC dated January 13, 2003. Thus, only those contents in Table 4.1.2-2A that differ from those previously reported in Table 7-1 of WCAP-15571, Revision 0 need to be assessed and approved as part of the NRC staff's review of the EPU. Based on the above, the NRC staff finds the licensee's response to RAI J.8 acceptable with respect to determining which changes of the RV surveillance capsule withdrawal schedule would require the staff's review under Section III.B.3 of 10 CFR Part 50, Appendix H.

Table 2.1.1-2 of this SE (on the following page) provides a summary and comparison of how the RV surveillance capsule withdrawal schedule for BVPS-1, as defined in Table 4.1.2-2A of the EPULR, was updated for the EPU and compared with the previous withdrawal schedule provided in Table 7-1 of WCAP-15571, Revision 0. As can be noted from Table 2.1.1-2, the licensee withdrew Capsule V at 1.16 EFPY, Capsule U at 3.59 EFPY, Capsule W at 5.89 EFPY, and Capsule Y at 14.3 EFPY. These withdrawals were made during the refueling outages closest to the required times of withdrawal, as required in ASTM E185-82 for a five-capsule withdrawal schedule. Thus, the licensee's removals of the first four RV surveillance capsules from the BVPS-1 RV have been done in compliance with the requirements of ASTM E185-82, as invoked by 10 CFR Part 50, Appendix H and the EPU does not impact these capsule removals.

Table 4.1.2-2A of the EPULR continues to designate Capsule X as the fifth capsule for removal from the BVPS-1 RV and projects that this will be performed at 25.9 EFPY, when the capsule achieves an approximate neutron fluence of 5.87 x 10^{19} n/cm^2 (E > 1.0 MeV) at the time of removal. The NRC staff determined that RV inside surface neutron fluences predicted by dosimetry analysis in WCAP-15771 (the analysis report for Capsule Y) demonstrate that the BVPS-1 RV will have a limiting adjusted reference temperature value shift (ΔRT_{NDT} value) of 198.5 EF at EOL. In RAI J.2, the staff inquired whether or not the dosimetry analysis in WCAP-15771, Revision 0, accounted for the increase in neutron fluence that would occur at the RV clad-to-base metal interface as a result of the 8-percent EPU. Thus, RAI J.2 is relevant to determining whether 5.87 x 10^{19} n/cm^2 (E > 1.0 MeV) is a valid neutron fluence projection for the future removal of Capsule X. RAI J.2 is also relevant to assessing whether the limiting ΔRT_{NDT} value for BVPS-1, as based on the uprated neutron fluence projections for 27.44 EFPY, is projected to be in the 100 EF ! 200 EF range or above 200 EF, and thus whether the licensee would be required to remove a total of either four or five surveillance capsules for the current licensed operating period.

In its response to RAI No. J.2, the licensee clarified that the dosimetry analysis in WCAP-15571, Revision 0, only accounted for 1.4 percent of the total 9.4-percent increase in rated power to 2900 MWt (1.4 percent resulting from the measurement uncertainty recapture (MUR) uprate and 8 percent from the EPU). The licensee stated that, to account for the remaining 8-percent increase in rated power to 2900 MWt, the licensee has supplemented the neutron fluence analysis for BVPS-1 and provided the analysis in Section 6.5 of EPULR. The revised neutron fluence analysis in the EPULR conservatively assumed that the EPU for BVPS-1 has been in effect since 2003. Section 6.5 and Table 6.5-1A of the EPULR indicate that the limiting uprated neutron fluence for the clad-to-base metal interface of the BVPS-1 RV is 3.54 x 10^{19} n/cm^2 (E > 1.0 MeV) at EOL. In Section 2.8.4.3 of this SE, the staff determined that the uprated dosimetry analysis for BVPS-1 in Section 6.5 of the EPULR was acceptable and appropriately accounted for the increase in neutron fluence attributed to the EPU. Thus,

Section 4.1.2 of the EPULR appropriately projects that the limiting uprated ΔRT_{NDT} value for the clad-to-base metal interface of the BVPS-1 RV will be 202 EF at EOL. Based on this limiting uprated ΔRT_{NDT} value, FENOC will still be required to remove a fifth RV surveillance capsule during the current operating cycle for the unit.

Table 2.1.1-2 Comparison of BVPS-1 RV Material Surveillance Program Withdrawal Schedule Defined in Table 7-1 of WCAP-15571, Revision 0 to that Updated in Table 4.1.2-2A of the BVPS EPULR

Capsule	Location	Lead Factor [(a)]		Removal Time (EFPY)[(b)]		Neutron Fluence [(a)] (n/cm^2 , E > 1.0 MeV)	
		Table 7-1, WCAP-15571, Rev. 0	EPULR Table 4.1.2-2A	Table 7-1, WCAP-15571, Rev. 0	EPULR Table 4.1.2-2A	Table 7-1, WCAP-15571, Rev. 0	EPULR Table 4.1.2-2A
V	165E	1.60	1.60	1.16	1.16	3.23x10^{18}	3.23x10^{18}[©)]
U	65E	1.05	1.10	3.59	3.59	6.46x10^{18}	6.46x10^{18}[©)]
W	245E	1.09	1.09	5.89	5.89	9.86x10^{18}	9.86x10^{18}[©)]
Y	295E	1.22	1.22	14.3	14.3	2.15x10^{19}	2.15x10^{19}[©)]
X	285E	1.76	1.76	25.7	25.9	5.82x10^{19}	5.87x10^{19}[(f)]
T	55E	(d)	(d)	Standby	Standby	---	---
Z	305E	(f)	(f)	Standby	Standby	---	---
S	45E	0.63	0.54	Standby	Standby	---	---

Footnotes

(a) As reported from the dosimetry analysis in WCAP-15771, Revision 0, "Analysis of Capsule Y from Beaver Valley Unit 1 Reactor Vessel Radiation Surveillance Program [November 2000]."

(b) Elapsed time in EFPY.

©) Actual plant-evaluation calculated neutron fluence values for these capsules, as reported in WCAP-15771, Revision 0.

(d) Capsule T, Z, and S are designated as a standby capsules. Capsule T was moved to the Capsule U location at the end of cycle 10. The lead factor for Capsule T was approximately 0.77 through the first 10 cycles. The average lead factor for Capsule T during cycles 11 and higher is 0.95.

(e) Capsule Z was moved to the Capsule V location at the end of cycle 10. The lead factor for Capsule Z was approximately 0.77 through the first 10 cycles. The average lead factor for Capsule Z during cycles 11 and higher is 1.11.

(f) This neutron fluence is projected to be equivalent to that for the limiting neutron fluence at clad-base-metal interface at 45 EFPY. Table of 4.1.2-2A of the EPULR report projects the neutron fluence for Capsule X will be 5.87x10^{19} n/cm^2 [E > 1.0 MeV] at the time of capsule removal, which is a minor adjustment of the neutron fluence value projected in WCAP-15771, Revision 0 (i.e., 5.82 x 10^{19} n/cm^2 [E> 1.0 MeV]). Table 4.1.2-2A of the EPULR projects that Capsule X will be removed at 25.9 EFPY, which is a minor adjustment of the previous time projected for capsule removal in WCAP-15771, Revision 0 (i.e, 25.7 EFPY).

Based on the above, the NRC staff finds the licensee's response to RAI No. J.2 acceptable with respect to determining whether FENOC will continue to be required to remove a fifth RV surveillance capsule in accordance with the BVPS-1 RV surveillance capsule withdrawal schedule.

The licensee projects that Capsule X will be removed at a projected fluence of 5.87 x 10^{19} n/cm^2 (E > 1.0 MeV). This removal is projected to occur at the time when the neutron fluence for the

capsule will be between one and two times the limiting neutron fluence for the RV at EOL (i.e., between one and two times the projected fluence of 3.54 x 10^{19} n/cm^2 [E > 1.0 MeV] for the clad-to-base metal interface of the RV at EOL). This is in compliance with criteria of ASTM E185-82 and is acceptable. Capsules T, Z, and S remain as additional standby capsules for the BVPS-1 RVMSP.

Based on this assessment, the NRC staff concludes that the RV surveillance capsule withdrawal schedule in Table 4.1.2-2A of the EPU licensing report conforms to the withdrawal schedule criteria in ASTM E185-82, and therefore, meets the requirements of 10 CFR Part 50, Appendix H, and is acceptable for implementation.

Impact of the 8-percent EPU on the BVPS-2 RV Surveillance Capsule Withdrawal Schedule

The current docketed version of the licensee's RV materials surveillance withdrawal schedule for BVPS-2 is given in Table 7-1 of WCAP-15675, Revision 0, "Analysis of Capsule W from FirstEnergy Nuclear Operating Company Beaver Valley Unit 2 Reactor Vessel Radiation Surveillance Program." Table 4.1.2-2B of the EPULR provides the most recent proposed RV surveillance capsule withdrawal schedules for BVPS-2. Table 4.1.2-2B resubmitted the same surveillance capsule withdrawal schedule for BVPS-2 that was proposed in Table 7-1 of WCAP-15675, Revision 0, with the exception that Table 4.1.2-2B made a minor revision of the lead factors, projected withdrawal times, and/or projected neutron fluence for BVPS-2 capsules.

In RAI J.8, the NRC staff inquired whether the licensee was requesting review and approval of the new RV surveillance capsule withdrawal schedule for BVPS-2, as summarized in Table 4.1.2-2B of the EPULR. RAI J.8 is relevant to determining whether the withdrawal schedule in Table 4.1.2-2B for BVPS-2 had been reviewed and approved by the staff, as would need to be done in order to comply with Section III.B.3 of 10 CFR Part 50, Appendix H.

In its response to RAI No. J.8, the licensee stated that the impact of the EPU on the RV surveillance capsule withdrawal for BVPS-2 is adequately addressed in Section 4.1.2 of the EPULR. In FENOC's supplemental response to RAI J.8, the licensee confirmed that the previous withdrawal schedule for BVPS-2, as provided in WCAP-15675, Revision 0, was approved in an SE issued to FENOC on March 19, 2002. Thus, only those items in Table 4.1.2-2B of the EPULR that differ from those previously reported in Table 7-1 of WCAP-15675, Revision 0, need to be assessed as part of the NRC staff's review of the EPU. Based on the above, the NRC staff finds the licensee's response to RAI J.8 acceptable with respect to determining which changes of the RV surveillance capsule withdrawal schedule would require the staff's review under Section III.B.3 of 10 CFR Part 50, Appendix H.

Table 2.1.1-3 of this SE provides a summary and comparison of how the RV surveillance capsule withdrawal schedule for BVPS-2, as defined in Table 4.1.2-2B of the EPULR, was updated for the EPU and compared with the previous withdrawal schedule provided in Table 7-1 of WCAP-15675, Revision 0. As indicated in Table 2.1.1-3 of this SE, the staff determined that the licensee withdrew Capsule V at 1.24 EFPY, Capsule U at 5.98 EFPY, and Capsule W at 9.77 EFPY. These withdrawals were made during the refueling outages closest to the required times of withdrawal, as summarized for a 4-capsule ASTM withdrawal schedule in Table 2.1.1-1 of this SE. Therefore, the licensee's removals of the first three RV surveillance capsules from the BVPS-2 RV have been done in compliance with the requirements of ASTM

E185-82, as invoked by 10 CFR Part 50, Appendix H and the EPU does not impact these capsule removals.

The NRC staff confirmed that dosimetry analyses in Tables 6 and 7 of WCAP-15675, Revision 0, have accounted for the increased neutron flux that will result from implementation of an 8-percent EPU at BVPS-2. The staff determined that RV inside surface neutron fluences obtained by dosimetry analysis in WCAP-15675, Revision 0 (the analysis report for BVPS-2 Capsule W, which is the 3rd surveillance capsule removed in accordance with the RVMSP), predict that the BVPS-2 RV has a limiting ΔRT_{NDT} value of 68.8 EF for the inside surface of the RV at EOL.

Table 2.1.1-3 Comparison of BVPS-2 RV Material Surveillance Program Withdrawal Schedule Defined in Table 7-1 of WCAP-15571, Revision 0 to that Updated in Table 4.1.2-2B of the BVPS EPULR.

Capsule	Location	Lead Factor (a)		Removal Time (EFPY)(b)		Neutron Fluence (a) (n/cm^2 , E $ MeV)	
		Table 7-1, WCAP-15675, Rev. 0	EPULR Table 4.1.2-2B	Table 7-1, WCAP-15675, Rev. 0	EPULR Table 4.1.2-2B	Table 7-1, WCAP-15675, Rev. 0	EPULR Table 4.1.2-2B
V	343E	3.17	3.17	1.24	1.24	$6.08X10^{18}$	$6.08x10^{18}$ ©)
U	107E	3.64	3.64	5.98	5.98	$2.63X10^{19}$	$2.63x10^{18}$ ©)
W	110E	3.29	3.29	9.77	9.77	$3.625X10^{19}$	$3.63x10^{18}$ ©)
X	287E	3.71	3.71	14	14	$5.77X10^{19}$	$5.84x10^{19}$ (d)
Y(e)	290E	3.22	3.29	Standby	Standby	---	---
Z(e)	340E	3.22	3.29	Standby	Standby	---	---

Footnotes

(a) As reported from the dosimetry analysis in WCAP-15675, Revision 0, *Analysis of Capsule W from FirstEnergy Nuclear Operating Company Beaver Valley Unit 2 Reactor Vessel Radiation Surveillance Program* [August 2001].

(b) Elapsed time in EFPY.

©) Actual plant-evaluation calculated neutron fluence values for these capsules, as reported in WCAP-15675, Revision 0.

(d) Approximately equal to the projected peak vessel fluence at 48 EFPY, but not less than once or greater than twice the maximum EOL (32 EFPY) inner vessel wall fluence.

(e) These capsules will reach a neutron fluence of approximately $6.58x10^{19}$ n/cm^2 (i.e., the projected 54 EFPY peak fluence [E > 1.0 MeV]) at 17 EFPY. It is recommended that these standby capsules be withdrawn and placed in storage.

The licensee is only required by ASTM E185-82 to remove three surveillance capsules from the BVPS-2 RV for the current licensed operating period, as the RV has projected limiting ΔRT_{NDT} value that is less than 100 EF. However, the licensee's new RV surveillance capsule withdrawal schedule in EPULR Table 4.1.2-2B continues to designate that a fourth surveillance capsule (Capsule X) will be withdrawn from the BVPS-2 RV for the current operating term at 14 EFPY and projects that the capsule will have achieved a neutron fluence of 5.84×10^{19} n/cm^2 (E > 1.0 MeV) at the time of removal. This will accomplish two purposes:

(1) The withdrawal of the non-required capsule meets the intent of ASTM Standard

E185-82 for the current licensed operating period in that the achieved fluence will be "not less than once or greater than twice the peak EOL vessel fluence," and thus the capsule withdrawal will meet the intent of the neutron fluence requirement for the final capsule that is removed in accordance with an RV surveillance capsule withdrawal schedule.

(2) When removed, the capsule will achieve a neutron fluence that is the peak neutron fluence projected to occur at the inside surface of the RV at 54 EFPY, and thus the surveillance data obtained from tests on the capsule's test specimens could be used to support a license renewal application (LRA) for the reactor, if an LRA is applied for by the licensee.

Capsules Y and Z remain as additional standby capsules for the BVPS-2 RVMSP.

Based on this assessment, the NRC staff concludes that the RV surveillance capsule withdrawal schedule in Table 4.1.2-2B of the EPULR conforms to the withdrawal schedule criteria in ASTM E185-82, and therefore, meets the requirements of 10 CFR Part 50, Appendix H and is acceptable for implementation.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the RV surveillance capsule withdrawal schedules for BVPS-1 and 2 and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the schedule. The NRC staff further concludes that the RV surveillance capsule withdrawal schedules for BVPS-1 and 2 are appropriate to ensure that the BVPS-1 and 2 RVMSPs will continue to meet the requirements of 10 CFR Part 50, Appendix H and 10 CFR 50.60, and will provide the licensee with information to ensure continued compliance with GDCs 14 and 31, in this respect, following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the BVPS-1 and 2 RVMSPs and that the RV surveillance capsules withdrawal schedules in Tables 4.1.2-2A and 4.1.2-2B of the EPULR may be implemented by the licensee.

2.1.2 Pressure-Temperature (P-T) Limits and Upper-Shelf Energy

Regulatory Evaluation

Appendix G to 10 CFR Part 50 provides fracture toughness requirements for ferritic materials (low alloy steel or carbon steel) in the reactor coolant pressure boundary (RCPB), including requirements on the upper shelf energy (USE) values used for assessing the remaining safety margins of the RV materials against ductile tearing and requirements for calculating P-T limits for the plant. These P-T limits are established to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including anticipated operational occurrences and hydrostatic tests. The NRC staff's review of the USE assessments covered the impact of the EPU on the neutron fluence values for the RV beltline materials and the USE values for the RV materials through the end of the current licensed operating period for BVPS-1 and 2. The staff's review of the P-T limits covered the P-T limits methodology and the calculations for the number of the EFPY specified for the proposed EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics.

The NRC's acceptance criteria for P-T limits are based on (1) GDC 14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (2) GDC 31, which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix G. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of NRC Review Standard, RS-001, Revision 0.

Technical Evaluation

Section IV.A.1 of 10 CFR Part 50, Appendix G, requires RV beltline materials to have a minimum USE value of 75 ft-lb in the unirradiated condition and to maintain a minimum USE value above 50 ft-lb throughout the life of the facility, unless it can be demonstrated through an analytical engineering evaluation that lower values of USE would provide acceptable margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code. The rule also mandates that the methods used to calculate USE values must account for the effects of neutron irradiation on the USE values for the materials and must incorporate any relevant RV surveillance capsule data that are reported through implementation of a plant's 10 CFR Part 50, Appendix H, RV materials surveillance program. The neutron fluence values used in the USE calculations are those for RV beltline materials at the one-quarter thickness (1/4T) location of the RV, as projected to EOL.

Section IV.A.2 of 10 CFR Part 50, Appendix G, requires that the P-T limits for operating reactors be at least as conservative as those that would be generated if the methods of calculation in the ASME Code, Section XI, Appendix G were used to calculate the P-T limits. The rule also requires that the P-T limit calculations account for the effects of neutron irradiation on the P-T limit values for the RV beltline materials and to incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its RVMSP.

The licensee discussed the impact of the 8-percent EPU on the USE values and P-T limit curves for the BVPS-1 and 2 RV beltline materials in Section 4.1.2 of the EPULR.

Impact of the 8-percent EPU on the USE Analysis for BVPS-1

The licensee stated that the revised neutron fluences for the EPU are projected to be above those projected for BVPS-1 in WCAP-15771, Revision 0 (the BVPS-1 Capsule Y Report), but added that 1/4T neutron fluence values for the BVPS-1 RV beltline materials were less than 1 percent greater than the values projected in WCAP-15771, Revision 0. The licensee stated that, based on the dosimetry results of WCAP-15771, Revision 0, all of the BVPS-1 RV beltline materials were projected to have USE values above 50 ft-lb at EOL, as assessed for the RV beltline materials at the 1/4T location of the RV.

The NRC staff determined that WCAP-15771, Revision 0, did not project the EOL 1/4T neutron fluences based on the EPU conditions and did not include any USE value calculations for the BVPS-1 RV beltline materials. In RAI No. J.1, the staff inquired how the 1/4T neutron fluences for the BVPS-1 RV beltline materials were calculated to account for the EPU-based conditions.

In RAI J.5, the staff asked the licensee to specify what the weight-percent copper (wt.-percent Cu) values were for the RV surveillance plate and weld materials that are within the scope of the BVPS-1 RVMSP. In RAI No. J.7, the staff requested that the EPU-based USE values at EOL be submitted for BVPS-1.

The licensee provided its responses to RAIs J.1, J.5, and J.7 in Reference 9. In its response to RAI No. J.1, the licensee clarified that, the dosimetry analysis in WCAP-15571, Revision 0 only accounted for 1.4 percent of the total 9.4 percent increase in rated power to 2900 MWt (1.4 percent resulting from the MUR update and 8 percent from the EPU). The licensee stated that, to account for the remaining 8-percent increase in rated power to 2900 MWt, the licensee supplemented the neutron fluence analysis for BVPS-1 and provided the analysis in Section 6.5 of EPULR. The revised neutron fluence analysis conservatively assumed that the EPU for BVPS-1 has been in effect since 2003. Section 6.5 and Table 6.5-1A of the EPULR indicate that the limiting uprated neutron fluence for the clad-to-base metal interface of the BVPS-1 RV is 3.54×10^{19} n/cm^2 (E > 1.0 MeV) at EOL. The licensee indicated that the EPU-based neutron fluences for the 1/4T location of the BVPS-1 RV are derived from the limiting uprated neutron fluence for RV clad-to-base metal interface locations by applying the neutron fluence attenuation equation in NRC RG 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” May 1988. In Section 2.8.4.3 of this SE, the staff evaluated the uprated dosimetry analysis for BVPS-1 that was discussed in Section 6.5 of the EPULR and concluded that the uprated dosimetry analysis for BVPS-1 appropriately accounted for the increase in neutron fluence attributed to the EPU. Thus, RAI J.1 is resolved with respect to assuring that the USE assessment for BVPS-1 has appropriately accounted for the impact of the EPU on the EOL neutron fluence values for the 1/4T location of the RV.

In its response to RAI No. J.5, the licensee clarified that 0.21 wt.-percent Cu and 0.54 wt.-percent Ni are valid alloying chemistry values for the BVPS-1 surveillance plate material fabricated from plate heat No. C6317-1, which is representative of BVPS-1 lower shell plate B6903-1. The response to RAI J.5 also confirmed that 0.29 wt.-percent Cu and 0.63 wt.-percent Ni are valid alloying chemistry values for the BVPS-1 surveillance weld material fabricated from weld heat No. 305424, which is representative of BVPS-1 intermediate shell axial welds 9-714 A and B. For the BVPS-1 surveillance weld material, the licensee confirmed that the pedigree of the data is from Report CE NPSD-1039, Revision 1, “Best Estimate Copper and Nickel Values in DE Fabricated Reactor Vessel Welds [April 1997],” with three additional chemistry data points obtained from WCAP-15571 (the Capsule Y Report). For the BVPS-1 surveillance plate, the licensee clarified the pedigree of data was reported in WCAP-15570, with an additional data point from WCAP 15571 being taken into account. This provides the appropriate update of the pedigree of data for the surveillance plate and weld materials since the time Report CE NPSD-1039, Revision 1, was reported to the NRC staff and the time WCAP-15770 was submitted for BVPS-1. Based on the above, the NRC staff finds the licensee’s response to RAI No. J.5 acceptable with respect to confirming what the alloying chemistry values and what the pedigree sources are for the BVPS-1 surveillance materials.

In its response to RAI No. J.7, the licensee provided its USE calculations for the RV beltline material at BVPS-1, as based on the uprated one-quarter RV thickness (1/4T) neutron fluences for the RV beltline materials at EOL. Based on the licensee’s assessment, the licensee reports that lower shell plate No. B6903-1 (Heat No. C6317-1) is the limiting material for USE at BVPS-1 under uprated conditions and that the limiting USE value for this material is projected to be 56

ft-lbs at EOL, as based on use of relevant surveillance data and calculated in accordance with Position 2.2 of RG 1.99, Revision 2. This value is in compliance with the 50 ft-lb acceptance criterion of Appendix G to 10 CFR Part 50 for USE values at the expiration of the current operating license.

The NRC staff performed an independent calculation of the EOL USE values for the BVPS-1 RV beltline materials in accordance with the USE methods in RG 1.99, Revision 2. The staff performed its calculation using the limiting 1/4T neutron fluence values for the RV beltline materials at EOL and the alloying chemistry and USE data provided in the EPULR and in the licensee's responses to RAI Nos. J.1, J.5, and J.7. The staff confirmed that, under the EPU conditions, lower shell plate No. B6903-1 (Heat No. C6317-1) is the limiting beltline material for USE and calculated a USE value of 53.8 ft-lb for this material at EOL.

The NRC staff's USE value for this material is slightly lower than the USE value calculated by the licensee for this material because the staff applied the unirradiated USE (UUSE) value of 80 ft-lb that was reported for the material in a Duquesne Light Company letter of September 10, 1993, to the NRC. In contrast, the licensee applied a slightly less conservative USE value of 83 ft-lb for its USE assessment of this material, which accounts for the slight difference in the calculated values. Both of these USE values are in excess of the 50 ft-lb EOL USE requirement in 10 CFR Part 50, Appendix G, and are acceptable. Therefore, based on this assessment, the staff concludes that the beltline materials in the BVPS-1 RV will have acceptable remaining values of USE at EOL under the EPU conditions. RAI J.7 is resolved with respect to providing the EPU-based USE calculations for the BVPS-1 RV beltline materials.

Impact of the 8-percent EPU on the USE Analysis for BVPS-2

The licensee also stated that the revised EPU-based neutron fluences for BVPS-2 RV beltline materials at 32 EFPY were accounted for in WCAP-15675, Revision 0 (the BVPS-2 Capsule W Report), and that based on these fluences, all of the BVPS-2 RV beltline materials are projected to have USE values above 50 ft-lb at EOL, as assessed for the neutron fluences at the 1/4T location of the RV. For completeness of the application, Section 6.5 provided the EPU-based neutron fluence assessment for BVPS-2, which is derived from the EPU-based dosimetry analysis in WCAP-15675, Revision 0. Section 6.5 and Table 6.5-1B of the EPULR indicate that the limiting uprated neutron fluence for the clad-to-base metal interface of the BVPS-2 RV is 3.84×10^{19} n/cm^2 (E > 1.0 MeV) at EOL.

The NRC staff determined that WCAP-15675, Revision 0, did not include any USE value calculations for the BVPS-2 RV beltline materials. In RAI J.5, the staff asked the licensee to specify what the wt.-percent Cu values were for the RV surveillance plate and weld materials that are within the scope of the BVPS-2 RVMSP. In RAI No. J.7, the staff asked how the EPU-based USE values for the BVPS-2 RV beltline materials at EOL were calculated and requested that the EPU-based USE values be submitted for BVPS-2.

In its response to RAI No. J.5, the licensee clarified that 0.06 wt.-percent Cu and 0.57 wt.-percent Ni are valid alloying chemistry values for the BVPS-2 surveillance plate material fabricated from plate heat No. C0544-2, which is representative of BVPS-2 intermediate shell plate B9005-1. The response to RAI J.5 also confirmed that 0.080 wt.-percent Cu and 0.070 wt.-percent Ni are valid alloying chemistry values for the BVPS-2 surveillance weld material fabricated from weld heat No. 83642, which is representative of the BVPS-2 lower and

intermediate shell axial welds and the BVPS-2 lower shell to intermediate shell circumferential weld. For the surveillance weld material, the pedigree of the data is from Report CE NPSD-1039, Revision 1. For the surveillance plate material, the pedigree of the data is from WCAP-15677, “Beaver Valley Unit 2 Heatup and Cooldown Curves for Normal Operation,” August 2001, which reports three data points for the surveillance plate material. This provides the appropriate update of the pedigree of data for the surveillance plate and weld materials since the time Report CE NPSD-1039, Revision 1 was submitted to the staff and the time WCAP-15677 was submitted for BVPS-2. Based on the above, the NRC staff finds the licensee’s response to RAI No. J.5 acceptable with respect to confirming what the alloying chemistry values and what the pedigree sources are for the BVPS-2 surveillance materials.

In its response to RAI No. J.7, the licensee provided its USE calculations for the RV beltline material at BVPS-2, as based on the uprated neutron fluences for the materials at EOL. Based on the licensee’s assessment, lower shell plate B9005-2 (Heat No. C1408-1) is the limiting material for USE at BVPS-2 under uprated conditions and the limiting USE value for this material is projected to be 60 ft-lbs at EOL, based on calculations performed in accordance with Position 1.2 of RG 1.99, Revision 2. This value is in compliance with the 50 ft-lb acceptance criterion of 10 CFR Part 50, Appendix G, for USE values at the expiration of the current operating license.

The NRC staff performed an independent calculation of the EOL USE values for the BVPS-2 RV beltline materials using the limiting 1/4T neutron fluence values for the materials at 32 EFPY, as reported in WCAP-15675, Revision 0. The staff’s independent assessment included the incorporation of the pertinent surveillance data reported in WCAP-15675, Revision 0, and the wt.-percent Cu values for the BVPS-2 surveillance plate and weld materials that were provided in the licensee’s response to RAI J.5. The staff confirmed that, under the EPU conditions, lower shell plate B9005-2 (Heat No. C1408-1) is the limiting beltline material for USE and calculated a 59.43 ft-lb USE value for this material at EOL. This USE value is in good agreement with the limiting 32 EFPY USE value cited by the licensee for this material and exceeds the 50 ft-lb EOL USE requirement in 10 CFR Part 50, Appendix G. Therefore, the staff concludes that the beltline materials in the BVPS-2 RV will have acceptable remaining values of USE under the EPU conditions for the unit. The staff finds the licensee’s response to RAI J.7 acceptable with respect to providing the EPU-based USE calculations for the BVPS-2 RV beltline materials.

Impact of the 8-percent EPU on the P-T Limits for BVPS-1 and BVPS-2

In Section 4.1.2 of the EPULR, the licensee stated that P-T limit curves for BVPS-1 were established based on the 1/4T and three-quarter thickness (3/4T) neutron fluences for the RV at 22 EFPY and at EOL. The licensee stated that these P-T limit curves for BVPS-1 were calculated using the latest revised neutron fluence analysis reported for the unit in WCAP-15571, Revision 0 (i.e., the Surveillance Capsule Report for BVPS-1 Capsule Y). The curves do account for the changes in 1/4T and 3/4T neutron fluence values associated with the measurement recapture uncertainty power uprate for the facility, which was granted in a license amendment for the facilities dated September 24, 2001. However, in the EPULR, the licensee stated that the current P-T limit curves for BVPS-1 at 22 EFPY and at EOL did not account for the increases in 1/4T and 3/4T neutron fluence that would result from the proposed EPU.

In RAI J.1, the NRC staff asked how the changes to the 1/4T and 3/4T neutron fluences for the BVPS-1 RV materials would impact the P-T limits for BVPS-1. In RAI J.3, the staff asked how the 1/4T and 3/4T neutron fluences for the BVPS-1 RV materials, as adjusted for EPU conditions, were accounted for in the P-T limit curves for BVPS-1 at 22 EFPY and at EOL.

In its response to RAI J.1, the licensee provided its basis on how the neutron fluence calculations reported in WCAP-15571, Revision 0, were modified to account for the impacts of both an MUR power uprate and an EPU (for a total 9.4-percent increase in RTP to 2900 MWt) and that this is born out in the EPU-based fluence assessment and revised EPU-based fluence values that are provided in Section 6.5 of the EPULR. In Section 2.8.4.3 of this SE, the NRC staff evaluated the EPU-based neutron fluence assessment for BVPS-1 and concluded that the uprated dosimetry analysis for BVPS-1 appropriately accounted for the increase in neutron fluence attributed to the EPU. Since the increase in power has been accounted for in the P-T limit curves, the staff concludes that the P-T limit curves for both BVPS-1 and BVPS-2 at EOL account for the impact of the MUR and EPU on the curves, and the NRC staff finds the licensee’s response to RAIs J.1 and J.3 acceptable.

For BVPS-2, the licensee stated that P-T limit curves were established for the 1/4T and 3/4T neutron fluences associated with 16 EFPY and 22 EFPY and that these P-T limit curves were provided in WCAP-15677. The licensee stated that the BVPS-2 P-T limit curves in WCAP-15677 were based on the updated dosimetry analyses in WCAP-15675 and that the WCAP-15675 dosimetry analyses accounted for the increase in the BVPS-2 1/4T and 3/4T neutron fluences as a result of the EPU. The licensee, therefore, stated that the 16 EFPY and 22 EFPY P-T limit curves for BVPS-2 would not need to be amended as a result of the EPU. This is consistent with the information provided in Table 4.1.2-3B of the EPULR. The staff has confirmed dosimetry analyses and neutron fluence values reported in WCAP-15675 do account for both the MUR (1.4 percent) uprated conditions that have already been implemented at BVPS-2 and the proposed 8-percent uprated conditions that will result from EPU. The staff, therefore, concludes that the current 16 EFPY and 22 EFPY P-T limit curves for BVPS-2 do not need to be amended as a result of the EPU.

The current licensing bases (CLBs) for BVPS-1 and 2 permit the licensee to administratively change the BVPS-1 and 2 P-T limit curves for normal operation and pressure test conditions in accordance with a pressure-temperature limits report (PTLR), without the need for a license amendment. Instead the changes to the P-T limit curves are done in accordance with an NRC-approved methodology that is specified in the PTLR and are controlled in accordance with administrative TS 6.9.6 of the BVPS-1 and 2 TSs. The PTLR for BVPS-1 and 2 was requested as an LAR in the FENOC letter dated October 31, 2001, as supplemented in FENOC letters of December 21, 2001, February 4, 2002, May 31, 2002, and December 2, 2002. The PTLR is based on the method of analysis and P-T limit relocation criteria of Generic Letter (GL) 96-03, “Relocation of Pressure Temperature Limit Curves and Low Temperature Overpressure Protection System Limits,” dated January 31, 1996, and the NRC-approved methodology for calculating P-T limits that is specified in WCAP-14040-NP-A, Revision 2, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,” January 1996. The NRC staff approved the BVPS-1 and 2 PTLR in an SE and license amendment, dated October 8, 2002, and again in a supplemental SE and license amendment, dated July 15, 2003. The license amendment of July 15, 2003, permitted FENOC to modify the methodology of WCAP-14040-NP-A, Revision 2, with methodology of ASME Code Case

N–640, which was approved for use in two exemptions granted to FENOC dated February 19, 2002 (for BVPS-1) and September 6, 2000 (for BVPS-2).

Based on the NRC staff's approval of the PTLR methodology, the licensee does not need to submit the necessary revision of the EPU-based P-T limit curves for BVPS-1 and 2 to the staff as a license amendment in accordance with 10 CFR 50.90. However, the licensee is required by BVPS-1 and 2 TS 6.9.6.c. to submit the PTLR to the NRC for information upon issuance for each reactor fluence period and for any revision or supplement, thereto (such as that which would occur as a result of the EPU). The licensee did not include updated PTLR for BVPS-1 as based on the EPU-based neutron fluences in the license amendment request for the EPU. In RAI J.4, the staff informed the licensee that subsection c. of TS 6.9.6 (TS 6.9.6.c) requires that following administrative reporting action of the licensee:

> The PTLR shall be provided to the NRC upon issuance for each reactor fluence period and for any revision or supplement, thereto.

In RAI J.4, the NRC staff asked the licensee to clarify how submission of only the uprated, revised PT limit curves for BVPS-1 and 2 would satisfy the intent of TS 6.9.6.c, as opposed to submitting the entire PTLR. Otherwise, the staff asked the licensee to submit the uprated PTLR for BVPS-1 and 2 as part of the 8-percent EPU request.

In its response to RAI J.4, the licensee also stated the EPU-based PTLR for BVPS-1 cannot be submitted to the NRC in accordance with administrative TS requirement 6.9.6.c until after the EPU LAR, the EPU-based neutron fluence values for BVPS-1, and the reductions in the expiration dates for the BVPS-1 P-T limit curves for 21.78 EFPY and for EOL have been approved by the NRC staff. This is within the bounds of the administrative process for PTLRs and is acceptable. The licensee will be required under Administrative TS 6.9.6.c to provide the EPU-based PTLR of BVPS-1 once the license amendment for the EPU has been approved by the staff. Since the reporting process in TS 6.9.6.c will require FENOC to submit the EPU-based PTLR for BVPS-1 at the appropriate time, RAI J.4 is resolved with respect to providing the EPU-based PTLR for BVPS-1.

In its response to RAI J.4, the licensee stated the EPU-based PTLR for BVPS-2, as based on the EPU-based fluences in WCAP-15677, was submitted to the NRC in accordance with administrative TS requirement 6.9.6.c in FENOC Letter No. L-05-063 to the NRC Document Control Desk dated March 21, 2005. Therefore, the licensee has complied with TS 6.9.6.c with respect to submitting the EPU-based PTLR for BVPS-2 and addressed the impact of the EPU on the BVPS-2 PTLR. RAI J.4 is resolved with respect to meeting the requirements for the BVPS-2 PTLR.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the USE values for the RV beltline materials at EOL and on the P-T limits for the plants. The staff concludes that the licensee has adequately addressed the changes in neutron fluence and their impacts on the USE values and the P-T limits for the plants. The staff concludes that the BVPS-1 and 2 RV beltline materials will continue to have acceptable USE values, as mandated by 10 CFR Part 50, Appendix G, through the expiration of the current operating licenses for the facilities. The NRC staff also concludes that the licensee's PTLR process, as mandated under

the administrative requirements of TS 6.9.6.c., will adequately address the impact of the 8-percent EPU on the P-T limits for normal, transient, and pressure test operating conditions. Based on this assessment, the staff concludes that the BVPS-1 and 2 facilities will continue to meet the requirements of 10 CFR Part 50, Appendix G and 10 CFR 50.60 and will enable the licensee to comply with GDC 14 and GDC 31 in this respect following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the EPU-based USE values and P-T limits for BVPS-1 and 2.

2.1.3 Pressurized Thermal Shock (PTS)

Regulatory Evaluation

The PTS evaluation provides a means for assessing the susceptibility of the RV beltline materials to PTS events to assure that adequate fracture toughness is provided to support reactor operation. The NRC staff's requirements, methods of evaluation, and safety criteria for PTS assessments are given in 10 CFR 50.61. The staff's review covered the PTS methodology and the calculations for the reference temperature, RT_{PTS}, at the expiration of the license, considering neutron embrittlement effects. The NRC's acceptance criteria for PTS are based on: (1) GDC 14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture; (2) GDC 31, which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (3) 10 CFR 50.61, which sets fracture toughness criteria for protection against PTS events. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of the NRC Review Standard, RS-001, Revision 0.

Technical Evaluation

10 CFR 50.61 requires licensees owning PWR-designed light-water reactors to calculate a nil-ductility reference temperature at EOL (i.e., an RT_{PTS} value for protecting the RV material against PTS) for each base metal and weld material in the RV beltline that is made from carbon or low-alloy steel materials. The rule also requires the RT_{PTS} values to be maintained below a maximum screening criterion throughout the service life of the facilities. The rule's screening criteria are 270 EF for axial weld materials and base metal materials (i.e., plates or forging materials) and 300 EF for circumferential weld materials.

Section 50.61 of 10 CFR Part 50, provides a required methodology for calculating these RT_{PTS} values, which are based on the calculation methods in RG 1.99, Revision 2. For materials in the beltline region of the vessel, the rule requires that the calculations account for the effects of neutron irradiation on the RT_{PTS} values for the materials and incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its RV materials surveillance program (i.e., 10 CFR Part 50, Appendix H, program).

In Section 4.1.2 of the EPULR, the licensee summarizes the requirements for PTS assessments in 10 CFR 50.61 and provides the uprated RT_{PTS} values for the BVPS-1 and 2 RV beltline base metal and weld materials, as calculated based on the 8-percent EPU uprated

neutron fluences for the materials at the clad-base-metal interface of the RVs and projected through EOL.

Impact of the 8-percent EPU on the PTS Assessment for BVPS-1

The results of the licensee's uprated RT_{PTS} calculation for the limiting BVPS-1 RV beltline material is given in Table 4.1.2-5A of the EPULR. In the table, the licensee identified that the BVPS-1 RV is limited by the evaluation for Lower Shell Plate B6903-1 (Plate Heat No. C6317-1) and projected that the RT_{PTS} value for this material will be 259 EF at EOL.

The NRC staff performed an independent calculation of the EOL RT_{PTS} values for the BVPS-1 RV beltline materials using the limiting uprated neutron fluence value for the clad-to-base metal interface location of the vessel at EOL. The staff's independent assessment included the incorporation of the pertinent surveillance data reported in WCAP-15771, Revision 0, for BVPS-1 Capsule Y.

The NRC staff required some additional information to complete its independent calculation of the limiting EOL RT_{PTS} value for BVPS-1 under EPU conditions. In RAI J.2, the staff asked the licensee whether the dosimetry and neutron fluence analysis in WCAP-15571, Revision 0, accounted for EPU-uprated conditions, and if not, what the EPU-based neutron fluences are projected to be for BVPS-1 at EOL. In RAI J.5, the staff asked the licensee to identify what the wt.-percent Cu and Ni values were for the surveillance plate and weld materials in the BVPS-1 RV surveillance program. In RAI J.6, the staff asked the licensee to provide its basis for changing the wt.-percent Cu value for BVPS-1 lower shell plate No. B6903-1 (Heat No. C6317-1).

The licensee provided its responses to RAIs J.2, J.5, and J.6 in FENOC Letter L-05-078, dated May 26, 2005 [9]. In its response to RAI No. J.2, the licensee clarified that the dosimetry analysis in WCAP-15571, Revision 0, only accounted for 1.4 percent of the total 9.4-percent increase in rated power to 2900 MWt (1.4 percent resulting from the MUR update and 8 percent from the EPU). The licensee stated that to account for the remaining 8-percent increase in rated power to 2900 MWt, the neutron fluence analysis for BVPS-1 was supplemented and provided in Section 6.5 of EPULR. The revised neutron fluence analysis conservatively assumes that the EPU for BVPS-1 has been in effect since 2003. Section 6.5 and Table 6.5-1A of the EPULR indicate that the limiting uprated neutron fluence for the clad-to-base metal interface of the BVPS-1 RV is 3.54×10^{19} n/cm^2 (E > 1.0 MeV) at EOL. The NRC staff has concluded that the uprated dosimetry analysis for BVPS-1 in Section 6.5 of the EPULR is acceptable and appropriately accounts for the increase in neutron fluence attributed to the EPU. Thus, RAI J.2 is resolved with respect to addressing the impact of the EPU on the EOL neutron fluence values for the RT_{PTS} calculations.

In its response to RAI No. J.5, the licensee clarified that 0.21 wt.-percent Cu and 0.54 wt.-percent Ni are valid alloying chemistry values for the BVPS-1 surveillance plate material fabricated from plate heat No. C6317-1, which is representative of BVPS-1 lower shell plate B6903-1. The response to RAI J.5 also confirmed that 0.29 wt.-percent Cu and 0.63 wt.-percent Ni are valid alloying chemistry values for the BVPS-1 surveillance weld material fabricated from weld heat No. 305424, which is representative of BVPS-1 intermediate shell axial welds 9-714 A and B. For the BVPS-1 surveillance weld material, the licensee confirmed that the pedigree of data is from Report CE NPSD-1039, with three additional chemistry data

points obtained from WCAP-15571 (the Capsule Y Report). For the BVPS-1 surveillance plate, the licensee clarified the pedigree of data was as reported in WCAP-15570, "Beaver Valley Unit 1 Heatup and Cooldown Limit Curves for Normal Operation [April 2001]," with an additional data point from WCAP-15571 being taken into account. This provides the appropriate update of the pedigree of data for the plate and weld materials since the date Report CE NPSD-1039 was submitted to the NRC staff and the dates that WCAP-15571 and WCAP-15770 were submitted for BVPS-1. Based on the above, the NRC staff finds the licensee's response to RAI No. J.5 acceptable with respect to confirming what the alloying chemistry values and what the pedigree sources are for the BVPS-1 surveillance materials.

In its response to RAI No. J.6, the licensee clarified that 0.21 wt.-percent Cu and 0.54 wt.-percent Ni are valid alloying chemistry values for the BVPS-1 surveillance plate material fabricated from plate heat No. C6317-1, which is representative of BVPS-1 lower shell plate B6903-1. The licensee stated that an additional alloying chemistry test was performed for this heat of material as a result of the surveillance tests that were performed on Capsule Y and which were reported in WCAP-15571. The licensee stated that this additional test resulted in an alloying content of 0.21 wt.-percent Cu and 0.53 wt.-percent Ni for this material, and, when averaged with the Cu and Ni values reported in the original Certified Mill Test Report (CMTR) (i.e., 0.20 wt.-percent Cu and 0.54 wt.-percent Ni), the two tests result in best-estimate averages of 0.205 wt.-percent Cu and 0.535 wt.-percent Ni for this heat of material. The licensee stated that these values are conservatively rounded up to 0.21 wt.-percent Cu and 0.54 wt.-percent Ni for use in the RT_{PTS} calculations. The NRC staff concludes that this is acceptable because the licensee has appropriately updated the Cu and Ni values for lower shell plate B6903-1 to account for the additional chemistry testing reported for Capsule Y in WCAP-15771 and because the averaging is in conformance with the staff's guidelines in NRC GL 92-01, Revision 1, Supplement 1, for deriving best-estimate chemistries for RV beltline materials. RAI No. J.6 is resolved with respect to establishing the best-estimate Cu and Ni values for the BVPS-1 RV beltline materials.

Based on the information in the EPULR and in the licensee's responses to RAIs J.2, J.5, and J.6, the NRC staff confirmed that lower shell plate B6903-1 (Plate Heat No. C6317-1) remains as the limiting BVPS-1 beltline material for PTS under uprated conditions. 10 CFR 50.61 sets a maximum PTS screening criterion of 270 EF for this material at EOL. The staff calculated an RT_{PTS} value of 259.5 EF for this material at EOL, based on the use of all plant-specific RV surveillance data that are applicable to the material and application of a full margin term of 34 EF to the calculations. In contrast, the staff calculated an RT_{PTS} value of 256.6 EF for this material at EOL when applying the chemistry factor table for base metals in 10 CFR 50.61 and a full margin term of 34 EF to the calculations. The RT_{PTS} value (i.e., 256.6 EF) calculated by the licensee for this material at EOL is within 4.0 EF and is in good agreement with the corresponding values calculated by the staff. Both the RT_{PTS} value cited by the licensee and the RT_{PTS} values calculated by the staff are below the PTS screening criterion of 270 EF. Based on this assessment, the staff concludes that the beltline materials in the BVPS-1 RV will remain in compliance with 10 CFR 50.61 and will have acceptable safety margins against the consequences of PTS events under the EPU-based conditions.

Impact of the 8-percent EPU on the PTS Assessment for BVPS-2

The results of the licensee's uprated RT_{PTS} calculation for the limiting BVPS-2 RV beltline material are given in Table 4.1.2-5B of the EPULR. In the table, the licensee identified that the BVPS-2 RV is limited by the evaluation for Intermediate Shell Plate B9004 (Plate Heat No. C0544-1) and projected that the RT_{PTS} value for this material will be 149 EF at EOL.

The NRC staff performed an independent calculation of the EOL RT_{PTS} values for the BVPS-2 RV beltline materials using the limiting 32 EFPY neutron fluence value for the clad-base metal interface location of the vessel under EPU conditions. The staff's independent assessment included the incorporation of the pertinent surveillance data reported in WCAP-15675, Revision 0, for BVPS-2 Capsule W.

The NRC staff required some additional information to complete its independent calculation of the limiting EOL RT_{PTS} value for BVPS-2 under EPU conditions. In RAI J.5, the staff asked the licensee to identify what the wt.-percent Cu and Ni values were for the surveillance plate and weld materials in the BVPS-2 RV surveillance program. In RAI J.6, the staff asked the licensee to provide its basis for changing the wt.-percent Cu and Ni value for BVPS-2 Intermediate Shell Plate B9004 (Plate Heat No. C0544-1).

In its response to RAI J.5, the licensee clarified that 0.06 wt.-percent Cu and 0.57 wt.-percent Ni are valid alloying chemistry values for the BVPS-2 surveillance plate material fabricated from plate heat No. C0544-2, which is representative of BVPS-2 intermediate shell plate B9005-1. The response to RAI J.5 also confirmed that 0.080 wt.-percent Cu and 0.070 wt.-percent nickel Ni are valid alloying chemistry values for the BVPS-2 surveillance weld material fabricated from weld heat No. 83642, which is representative of the BVPS-2 lower and intermediate shell axial welds and the BVPS-2 lower shell-to intermediate shell circumferential weld. For the surveillance weld material, the pedigree of the data is from Report CE NPSD-1039, Revision 1. For the surveillance plate material, the pedigree of the data is from WCAP-15677, which reports three data points for the surveillance plate material. This provides the appropriate update of the pedigree of data for the surveillance plate and weld materials since the date Report CE NPSD-1039, Revision 1, was submitted to the NRC staff and the date WCAP-15677 was submitted for BVPS-2. Based on the above, the NRC staff finds the licensee's response to RAI J.5 acceptable with respect to confirming what the alloying chemistry values and what the pedigree sources are for the BVPS-2 surveillance materials.

In its response to RAI J.6, the licensee clarified that, for intermediate shell plate B9004-1 (Heat No. C0544-1), the best-estimate Cu values of 0.065 wt.-percent Cu and 0.55 wt.-percent Ni are the best-estimate averages of 0.06 wt.-percent and 0.07 wt.-percent Cu and 0.53 wt.-percent and 0.57 wt.-percent Ni. The licensee also clarified that, for intermediate shell plate B9004-2 (Heat No. C0544-2), the best-estimate Cu value should be 0.06 wt.-percent Cu, as based on the information for the material in WCAP-15677. The licensee clarified that this Cu value is currently the value that is reported in the NRC's Reactor Vessel Integrity Database (RVID). The licensee clarified that WCAP-15677 lists three valid chemistry data points for Heat No. C0544-2 and that none of the Cu values exceed 0.07 wt.-percent Cu. The NRC staff finds that the licensee's best estimate Cu and Ni values for intermediate shell plates B9004-1 and B9004-2 are acceptable because they are based on average values from the existing pedigree of data for the plate materials and because the averaging is in conformance the staff's guidelines in GL 92-01, Revision 1, Supplement 1, for deriving best-estimate chemistries for RV beltline materials. Based on the above, the NRC staff finds the licensee's response to RAI J.6 acceptable.

The NRC staff confirmed that, under the EPU conditions, intermediate shell plate B9004-1 (Plate Heat No. C0544-1) is the limiting beltline material for PTS. 10 CFR 50.61 sets a maximum PTS screening criterion of 270 EF for this material at EOL. The staff calculated an RT_{PTS} value of 148.6 EF for this material at EOL. The RT_{PTS} value calculated by the licensee for material at EOL (i.e., 149 EF) is in agreement with the corresponding value calculated by the staff. Both the RT_{PTS} values calculated by the licensee and the staff are below the PTS screening criterion of 270 EF. The staff, therefore, concludes that the beltline materials in the BVPS-2 RV will have acceptable safety margins against the consequences of PTS events under the uprated power conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the PTS assessments for BVPS-1 and 2 and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on PTS. The NRC staff further concludes that the licensee has demonstrated that the plant will continue to meet the requirements of GDCs 14 and 31, and 10 CFR 50.61 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to PTS.

2.1.4 Reactor Internal and Core Support Materials

Regulatory Evaluation

The reactor internals and core supports include structures, systems, and components (SSCs) that perform safety functions or whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the reactor coolant system (RCS). The NRC staff’s review assessed the impact of the EPU on the margins of safety for maintaining the structural integrity of the RV internal and core support components. The NRC’s acceptance criteria for reactor internal and core support materials are based on GDC 1 and 10 CFR 50.55a for inspecting and evaluating the structural integrity of reactor internals and core support components. Specific review criteria are contained in SRP Section 4.5.2 and other review criteria and guidance are provided in Matrix 1 of NRC Review Standard, RS-001, Revision 0. For PWR-designed nuclear plants, Matrix 1 of RS-001, Revision 0, provides references to the NRC’s approval of the recommended guidelines for RV internals in Topical Reports WCAP-14577, Revision 1-A, “License Renewal Evaluation: Aging Management for Reactor Internals (March 2001)” and BAW-2248A, “Demonstration of the Management of Aging Effects for the Reactor Vessel Internals (March 2000).”

Technical Evaluation

The licensee discussed the impact of the EPU on the structural integrity of the BVPS-1 and 2 RV internal components in Section 4.1.3 of the EPULR. In its EPULR, the licensee evaluated the impact of the 8-percent EPU on stress-corrosion cracking (SCC) of austenitic stainless steel RV internals and on primary water stress-corrosion cracking (PWSCC) of RV internals made from Alloy 600. The NRC staff assesses the impact of the 8-percent EPU on SCC of austenitic stainless steel RV internals and of PWSCC of RV internals made from Alloy 600 in Section 2.1.5 of this SE. The licensee concluded that the 8-percent EPU would not impact the safety margins associated with the structural integrity of the BVPS-1 and 2 RV internal components.

The RV internals of PWR-designed light-water reactors may be susceptible to the following aging effects:

- cracking ! induced by thermal cycling (fatigue-induced cracking), SCC, or irradiation assisted stress-corrosion cracking (IASCC)
- loss of fracture toughness properties ! induced by radiation exposure for all stainless steel grades, or the synergistic effects of radiation exposure and thermal aging for cast austenitic stainless steel (CASS) grades;
- stress relaxation in bolted, fastened, keyed or pinned RV internal components ! induced by radiation exposure and/or exposure to elevated temperatures
- void swelling (induced by radiation exposure).

Table Matrix-1 of RS-001, Revision 0, provides the NRC staff's basis for evaluating the potential for EPUs to induce these aging effects. In Table Matrix-1, the staff states that, in addition to the SRP, guidance on the neutron irradiation-related threshold levels inducing IASCC in RV internal components is given in WCAP-14577, Revision 1-A.

WCAP-14577, Revision 1-A establishes a threshold of 1 X 10^{21} n/cm^{2} ($E \geq 0.1$ MeV) for the initiation of IASCC, loss of fracture toughness, and/or void swelling in PWR RV internal components made from stainless steel (including CASS) or Alloy 600/82/182 materials. In Table Matrix-1 of RS-001, Revision 0, the staff established guidance that plants exceeding this threshold of neutron radiation would either have to establish plant-specific degradation management programs for managing the aging effects associated with their RV internals or else indicate that the licensees would participate in industry programs designed for investigating and managing age-related degradation in the RV internal components.

The NRC staff issued RAI J.9 in order to get additional information on how the projected neutron fluences for the RV internals, at EOL under the 8-percent uprated conditions, compared to the neutron fluence threshold value established in WCAP-14577, Revision 1-A. In Part A of RAI J.9. the staff asked FENOC to provide the projected neutron fluence value for each RV internal at EOL under the 8-percent uprated conditions. In Part B of RAI J.9, the staff requested that the licensee submit a plant-specific program for managing aging or provide the following commitment for the power uprate if any neutron fluence values for the RV internals are projected to exceed the threshold value of 1 X 10^{21} n/cm^{2} ($E \geq 0.1$ MeV):

A "commitment to participate in and implement the Electric Power Research Institute's (EPRI's) Material Reliability Project (MRP) research initiatives on age- related degradation of RV internal components and to submit the inspection plan for the BVPS-1 and 2 RV internals for staff review and approval at least two years prior to the time when the limiting RV internal component is projected to exceed Westinghouse's threshold for IASCC."

The license provided the following commitment in FENOC Letter L-05-173, dated November 8, 2005, to address the potential for IASCC and other neutron irradiation-induced age-related degradation to occur in the BVPS-1 and 2 RV internal components:

<u>Commitment</u>

FirstEnergy Nuclear Operating Company (FENOC) is currently an active participant in the Electric Power Research Institute's (EPRI) Material Reliability Project (MRP) research initiatives

on aging related degradation of reactor vessel internals components, and committed to the following:

a. Continue its active participation in the MRP initiative to determine appropriate reactor vessel internals degradation management programs,

b. Evaluate the recommendations resulting from this initiative and implement a reactor vessel internals degradation management program applicable to BVPS Units 1 and 2,

c. Incorporate the resulting reactor vessel internals inspections into the BVPS Units 1 and 2 augmented inspection program, as appropriate.

The licensee's commitment to participate in the industry's research program on degradation of PWR RV internal components and to develop an inspection program for the RV internals that is based on the recommendations of the industry initiatives is consistent with Table Matrix-1 of RS-001, Revision 0, and is, therefore, acceptable. Based on this assessment, the staff concludes that FENOC has established an acceptable course of action for managing age-related degradation in the BVPS-1 and 2 RV internals under the 8-percent EPU conditions for the units.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RV internal and core support materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in operating temperature and neutron fluence on the integrity of these components. Consistent with Matrix 1 of RS-001, the staff further concludes that the licensee has committed to an augmented inspection program for the RV internal and core support components to ensure that the components will continue to meet the requirements of GDC 1 and 10 CFR 50.55a following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to maintaining the structural integrity of the RV internal and core support components.

2.1.5 Reactor Coolant Pressure Boundary Materials

Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff's review of the RCPB materials covered the design specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. The NRC's acceptance criteria for RCPB materials are based on: (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing and postulated accidents; (3) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (4) GDC 31, insofar as it requires that the RCPB

be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (5) 10 CFR 50.55a, Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB. Specific review criteria are contained in SRP Section 5.2.3 and other guidance provided in Matrix 1 of RS-001. Additional review guidance for PWSCC of dissimilar metal welds and associated inspection programs is contained in GL 97-01, Information Notice (IN) 00-17, Bulletin (BL) 01-01, BL 02-01, and BL 02-02. Additional review guidance for thermal embrittlement of CASS components is contained in a letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute (NEI), dated May 19, 2000. The licensee evaluated the effect of the proposed service conditions on the performance of RCS materials by using EPRI chemistry guidelines under "PWR Primary Water Chemistry Guidelines: Vol. 1, Rev. 5, TR-1002884," EPRI-MRP-117, "Inspection Plan for Reactor Vessel Closure Head Penetrations in US Power Plants," dated July 2004, and NRC First Revised Order dated February 20, 2004.

Technical Evaluation

The materials evaluated for the reactor coolant loop piping are austenitic stainless steel of wrought and cast product form and of Alloy 600 components including Alloy 82/182 weld locations. Under the EPU conditions, the cold leg temperature is estimated to drop below that of the current power conditions and the hot leg temperature is estimated to increase slightly. The cold leg temperature at the EPU conditions has no impact on the degradation of the reactor coolant piping materials that are evaluated for the currently rated thermal power because based on test data and operating experience, the lower the operating temperature, the lower probability of material degradation. The licensee has estimated the hot leg temperature to increase by 4 EF to a maximum value of 611.2 EF for BVPS-1 and by less than a degree to 609.5 EF for BVPS-2. The RCS pressure, however, remains unaffected at the EPU condition. The piping analyses previously performed to support a hot leg temperature of 617 EF which bounds the EPU conditions. Therefore, the analyses and evaluations will support operation at the EPU conditions with the RSGs for BVPS-1 and with original SGs for BVPS-2.

The NRC staff has further evaluated any potential degradation of piping material as a result of a small increase in hot leg temperature associated with EPU. The staff believes that the increase in hot leg temperature is negligible to enhance degradation of reactor coolant piping materials previously considered for the currently rated thermal power. However, in the licensee's submittal, the EPU considered a potential small increase in PWSCC susceptibility of Alloy 600 components in the RCS piping system. The licensee has further stated that it has established an Alloy 600 management program to manage and identify mitigative actions to address PWSCC of Alloy 600 material in the RCS utilizing a site specific assessment of each of the Alloy 600 and Alloy 82/182 weld locations. Under the licensee's Alloy 600 management program, all applicable components are ranked according to their susceptibility to PWSCC considering attributes such as, the time at the susceptible temperature, operating and residual stress, and the fabrication process. The resulting susceptibility index identifies each component's PWSCC susceptibility in relation to other components. This index establishes the basis for the site inspection plan.

The NRC staff evaluated PWSCC susceptibility of Alloy 600 components in the reactor vessel closure head (RVCH). The control rod drive mechanisms (CRDMs) in the vessel head are made of Alloy 600 material and the corresponding attachment welds are made with Alloy

82/182 material which are susceptible to PWSCC. At EPU conditions, the RVCH temperature in both BVPS-1 and 2 will increase from current temperature of 595 EF to 601.3 EF thus increasing the PWSCC susceptibility by a slight margin. However, BVPS-1 replaced the RVCH and the new RVCH utilizes Alloy 690 material which is more resistant to PWSCC than Alloy 600 material. The licensee has further stated that additional controls in fabrication of the RVCH would result in minimizing stresses in the CRDM penetration material and the dissimilar metal attachment welds. The replacement head utilizes attachment welds that are made of Alloy 52/152 material which is more resistant to PWSCC than the Alloy 82/182 material used in the original RVCH. In regard to the BVPS-2 RVCH, the CRDM penetrations will be inspected on a regular basis in accordance with NRC order EA 03-009 to ensure that no PWSCC concerns exist. Based on the above, the staff believes that the licensee’s existing Alloy 600 management program will be effective in identifying and initiating timely corrective action to PWSCC during operation at EPU conditions.

Conclusion

Based upon the NRC staff’s review of the information included in the licensee’s submittal, the staff concludes that the structural integrity of the RCS piping under the rated thermal power increase from 2689 MWt to 2900 MWt at BVPS-1 with the RSGs and at BVPS-2 with the original SGs (OSGs), is acceptable. The staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of RCPB materials. The staff further concludes that the licensee has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of GDCs 1, 4, 14, 31, 10 CFR Part 50, Appendix G, and 10 CFR 50.55a. Therefore, the staff finds the proposed EPU acceptable with respect to RCPB materials.

2.1.6 Leak-Before-Break (LBB)

Regulatory Evaluation

The LBB analyses provide a means for eliminating from the design basis the dynamic effects of postulated pipe ruptures for a piping system. NRC approval of LBB for a plant permits the licensee to (1) remove protective hardware along the piping system (e.g., pipe whip restraints and jet impingement barriers), and (2) redesign pipe-connected components, their supports, and their internals. The NRC staff’s review of LBB covered (a) direct pipe failure mechanisms (e.g., water hammer, creep damage, erosion, corrosion, fatigue, and environmental conditions); (b) indirect pipe failure mechanisms (e.g., seismic events, system overpressurizations, fire, flooding, missiles, and failures of SSCs in close proximity to the piping); and (c) deterministic fracture mechanics and leak detection methods. The NRC’s acceptance criteria for LBB are based on GDC 4, insofar as it allows for exclusion of dynamic effects of postulated pipe ruptures from the design basis. Specific review criteria are contained in draft SRP Section 3.6.3 and other guidance provided in Matrix 1 of RS-001.

Technical Evaluation

In Section 4.5 of the submittal, the licensee has stated that its current structural design basis of BVPS-1 and 2 utilizes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the primary reactor coolant piping and the pressurizer surge piping. The licensee states that the analyses and evaluations performed to demonstrate that the elimination of these breaks continues to be justified at the operating conditions associated with the EPU. For BVPS-2, the LBB methodology is also used for the branch line piping greater than 6-inch diameter. BVPS-1 has no Inconel 82/182 welds in the RCS main coolant loop and in the pressurizer surge line. However, BVPS-2 does have Inconel 82/182 welds in the RCS main coolant loop, the pressurizer surge line, the pressurizer safety valve, and the power operated relief valve lines. The licensee has stated that these welds were volumetrically examined and were found to contain no flaws. As stated earlier, the hot leg of primary loop piping will experience minor increase in its operating temperature. Therefore, the material properties were conservatively calculated at a higher temperature than that of the EPU condition (hot leg temperature of 617 EF, cold leg and cross-over leg temperature of 543.1 EF). For the surge line piping, the various operating temperatures used in the LBB evaluation, however, do not change with the EPU conditions and further evaluation is not required. Nevertheless, the licensee performed an LBB evaluation of the RCS primary loop piping using the new material properties. The results of the evaluation show that all the recommended margins of draft SRP Section 3.6.3 are satisfied, thus, demonstrating LBB behavior at the EPU conditions. The NRC staff finds that, with minor change in operating temperature and stress associated with the EPU conditions the material-related GDCs 4, 14, and 31 will continue to be met.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the LBB analysis for the plant and concludes that the licensee has adequately addressed changes in primary system pressure and temperature and their effects on the LBB analyses. The staff further concludes that the licensee has demonstrated that the LBB analyses will continue to be valid following implementation of the proposed EPU and that lines for which the licensee credits LBB will continue to meet the requirements of GDC 4. Therefore, the staff finds the proposed EPU acceptable with respect to LBB.

2.1.7 Protective Coating Systems (Paints)

Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance activities. The NRC staff's review covered protective coating systems used inside the containment for their suitability for and stability under design-basis loss-of-coolant (DBLOCA) conditions, considering radiation and chemical effects. The NRC's acceptance criteria for protective coating systems are based on (1) Title 10 of the *Code of Federal Regulations*, Part 50 (10 CFR 50), Appendix B, which provides quality

assurance requirements for the design, fabrication, and construction of safety-related structures, systems, and components; and (2) RG 1.54, Revision 1, Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants, for application and performance monitoring guidance of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2, Protective Coating Systems (Paints) - Organic Materials.

Technical Evaluation

Equipment and structures inside containment are protected from the environment during normal operating and accident conditions by protective coating systems (paints). In Section 10.14, Protective Coating Systems (Paints) - Organic Materials, of the EPU application, the licensee stated that the protective coating systems inside BVPS-1 and 2 containments comply with American National Standards Institute (ANSI) N101.2, Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities, design-basis accident (DBA) test requirements. As a result of the EPU, the containment protective coating systems will be exposed to slightly higher radiation levels, however, the licensee stated it will not exceed the ANSI N101.2 DBA testing values. The licensee also indicated that other DBA conditions that can affect coating qualification (i.e., chemical environment, temperature, and pressure) are not expected to change significantly and will remain bounding for EPU conditions. In addition, the licensee stated that all EPU environmental conditions will be bounded by the coating system testing for both BVPS-1 and 2. Coating failures will be identified during refueling operations and other containment surveillances by plant personnel and be entered into the site corrective action program. All coating repairs will be made with fully qualified coatings. The licensee concluded that the containment protective coating systems will be acceptable following EPU implementation and will continue to meet RG 1.54, Revision 0, acceptance criteria.

Conclusion

Based on its review, the NRC staff finds the licensee’s protective coating systems program adequate because the protective coatings will not be adversely impacted by EPU conditions during operation and the EPU accident conditions are bounded by the DBA testing values.

2.1.8 Flow Accelerated Corrosion

Regulatory Evaluation

Flow accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to single-phase or two-phase water flow. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on flow velocity, fluid temperature, steam quality, oxygen content, and pH. During plant operation, the ability to control these parameters in order to minimize the effects of FAC is limited. Loss of material by FAC will, therefore, occur. The NRC staff has reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee’s FAC program to predict the rate of loss so that

repair or replacement of damaged components could be made before reaching critical thickness. The licensee's FAC program consists of predicting loss of material using the EPRI CHECWORKS computer code, visual inspection, and volumetric examination of the affected components. The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

Technical Evaluation

FAC is a degradation mechanism in piping components caused by either single-phase or two-phase fluid flow. Carbon steel piping components in the power conversion system may undergo wall thinning due to FAC which can result in piping failure. Since undesirable challenges to the plant's safety systems may result from piping system component failure, licensees maintain a FAC related failure prediction, inspection, and component repair/replacement program. BVPS-1 and 2's FAC program defines criteria for susceptible piping segments, thickness measurement frequency, and repair/replacement decisions. The licensee stated that ultrasonic examination will be used for thickness measurements for its accuracy and repeatability. The EPRI CHECWORKS computer code along with select plant input (i.e., operating history, water chemistry history, inspection results) are used to predict FAC rates and adjust model predictions. In addition, the licensee has updated the FAC program models to reflect EPU conditions and they have been factored into future inspections and pipe replacement plans.

Conclusion

The NRC staff finds, based on its review, the licensee's FAC program is acceptable under EPU conditions because it is expected that the power uprate effect on FAC rates will be small and will continue to be managed by the existing FAC program.

2.1.9 SG Tube Inservice Inspection (ISI)

Regulatory Evaluation

SG tubes constitute a large part of the RCPB. SG ISI provides a means for assessing the structural and leakage integrity of the SG tubes through periodic inspection and testing of critical areas and features of the tubes. The NRC staff's review in this area covered the effects of changes in differential pressure, temperature, and flow rates resulting from the proposed EPU on plugging limits, potential degradation mechanisms (i.e., flow-induced vibration (FIV)), plant-specific alternate repair criteria (ARC), and redefined inspection boundaries. The NRC's acceptance criteria for SG tube ISI are based on 10 CFR 50.55a requirements for periodic inspection and testing of the RCPB. Specific review criteria are contained in SRP Section 5.4.2.2. Additional review guidance is contained in TS Section 3/4.4.4 for SG SRs; RG 1.121 for SG tube plugging limits; GL 95-03, Bulletin (BL) 88-02 for degradation mechanisms, structural and leakage performance criteria in NEI 97-06, and topical reports as applicable, all of which form the basis for ARC or redefined inspection boundaries.

Technical Evaluation

The NRC staff reviewed the licensee's EPU condition analyses of thermal-hydraulic performance, structural integrity, U-bend fatigue, hardware changes and additions, tube wear,

tube repair limit, and tube degradation for both BVPS-1 RSGs and BVPS-2 OSGs. The NEI 97-06 guidance has been implemented at BVPS-1 and 2.

Currently, the SGs at BVPS-2 are Westinghouse model 51 SGs. The model 51 SG contains 3,376 mill-annealed Alloy 600 tubes. Each tube has a nominal outside diameter of 0.875 inch and a nominal wall thickness of 0.050 inch. The tubes are supported by a number of carbon steel tube support plates and Alloy 600 anti-vibration bars (AVBs). The tubes in BVPS-2 SGs were roll expanded into the tubesheet at both ends for the full length of the tubesheet.

The BVPS-1 OSGs were replaced with model 54F SGs during the spring 2006 refueling outage. The replacement SGs contain tubes fabricated from thermally-treated Alloy 690 material as well as Type 405 stainless steel tube support plates and AVBs. The thermally-treated Alloy 690 tubing material is more resistant to SCC 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.

Feedwater flow, operating temperature, and sludge volume increase as a result of EPU conditions. In addition, SG tube crack initiation and crack growth rates may increase due to EPU conditions. New forms of degradation due to EPU conditions are not expected for the BVPS-1 RSGs or BVPS-2 OSGs. However, increased wear at the AVB tube supports may result from EPU conditions for the BVPS-2 OSGs. The licensee stated that the AVB wear growth rates are low such that the end-of-cycle (EOC) wear depth at EPU conditions will be below the structural limit.

In order to ensure that the inspection scope and techniques used will address all identified and potential degradation mechanisms, the licensee performs a degradation assessment prior to SG tube inspections in accordance with NEI 97-06. The licensee performs condition monitoring and operational assessment after the SG tube inspections to determine SG tube integrity at EOC. The condition monitoring compares the projected tube behavior from the previous cycle (operational assessment) with the actual results of the current cycle. In order to project SG tube integrity at the end of the next cycle, the licensee performs an operational assessment which accounts for expected cycle parameters. The condition monitoring and operational assessment results are compared to the tube burst and leakage performance criteria to ensure that acceptance criteria are met. The NRC staff finds this acceptable.

Conclusion

Based on its review of the licensee's implementation of degradation assessments prior to tube inspections, and its implementation of condition monitoring and operational assessments, the NRC staff concludes that the licensee has demonstrated that SG tube integrity will continue to be maintained and will continue to meet the performance criteria in NEI 97-06 and the requirements of 10 CFR 50.55a following implementation of the proposed EPU. In addition, the staff finds that the licensee adequately assessed the acceptability of BVPS-1 and 2 TSs and degradation management inspections under EPU conditions to ensure SG tube integrity. Therefore, the staff finds the proposed EPU acceptable with respect to SG tube ISI.

2.1.10 Steam Generator Blowdown System (SGBS)

Regulatory Evaluation

Control of secondary-side water chemistry is important for preventing degradation of SG tubes. The SGBS provides a means for removing SG secondary-side impurities and thus, assists in maintaining acceptable secondary-side water chemistry in the SGs. The design basis of the SGBS includes consideration of expected design flows for all modes of operation. The NRC staff's review covered the ability of the SGBS to remove particulate and dissolved impurities from the SG secondary side during normal operation, including condenser in-leakage and primary-to-secondary leakage. The NRC's acceptance criteria for the SGBS are based on GDC 14, Reactor Coolant Pressure Boundary, insofar as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture. Specific review criteria are contained in SRP Section 10.4.8, Steam Generator Blowdown System (PWR).

Technical Evaluation

The amounts of particulates and dissolved solids introduced by the feedwater system into the SGs are limited by the SGBS. In addition, secondary-side water samples are provided by the SGBS. The probability of secondary-side initiated SG tube degradation is reduced by proper control of the SG secondary-side water chemistry. The licensee evaluated the SGBS to ensure the system is capable of performing its intended function at EPU conditions. The impact of the EPU on the SGBS was evaluated for both the BVPS-1 RSGs and the BVPS-2 OSGs. The blowdown flow rates required to control secondary-side water chemistry and SG dissolved solids will not be impacted by EPU conditions since the required blowdown flow rates are based on parameters (i.e., allowable condenser in-leakage, allowable primary-to-secondary leakage, and total dissolved solids in the service water) not affected by the power uprate.

The licensee stated that an approximate 10- to 15-percent repositioning of the blowdown flow control valve may be required due to the minimum acceptable SG pressures being lowered for EPU conditions. This reduction in SG pressure reduces the maximum achievable blowdown mass flow rates, however, the licensee concluded that the capacity of the valves at the minimum operating pressures will be adequate for EPU conditions. Therefore, the licensee concluded that the SGBS is acceptable for operation at EPU conditions and the SGBS will continue to be monitored by the FAC program.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the power uprate on the SGBS. The staff concludes that the SGBS is acceptable for both the RSGs for BVPS-1 and the OSGs for BVPS-2, since the blowdown flow and the SG secondary-water chemistry are unchanged, and the blowdown pressures and temperatures remain within the original system design.

2.1.11 Chemical and Volume Control System (CVCS)

Regulatory Evaluation

The CVCS and boron recovery systems provide means for (1) maintaining water inventory and quality in the RCS, (2) supplying seal-water flow to the reactor coolant pumps and pressurizer auxiliary spray, (3) controlling the boron neutron absorber concentration in the reactor coolant, (4) controlling the primary-water chemistry and reducing coolant radioactivity level, and (5)

supplying recycled coolant for demineralized water makeup for normal operation and high-pressure injection flow to the emergency core cooling system in the event of postulated accidents. The NRC staff reviewed the safety-related functional performance characteristics of CVCS components. The NRC's acceptance criteria are based on (1) GDC 14, insofar as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture; and (2) GDC 29, Protection Against Anticipated Operational Occurrences, insofar as it requires that the reactivity control systems be designed to assure an extremely high probability of accomplishing their functions in the event of condenser in-leakage or primary-to-secondary leakage. Specific review criteria are contained in SRP Section 9.3.4, Chemical and Volume Control System (PWR).

Technical Evaluation

The CVCS's primary function is to maintain boron concentration, RCS inventory, and water chemistry. In addition, RCS purification and seal injection flow is provided to the RCPs by the CVCS. The RCS is serviced by a CVCS letdown and charging process during normal operation. RCS flow is letdown to the CVCS then returned via charging pumps to the RCS. The CVCS consists of several subsystems: boron thermal regeneration system, charging system, letdown system, reactor coolant purification and chemistry control system, seal water system, and reactor makeup control system. During maximum flow conditions, the letdown line decay time calculations require that the letdown line contain volume sufficient to delay flow from the RCS connection to the point where it leaves the containment. The licensee stated that the N-16 dose rate will increase under EPU conditions, however, this increase will be managed through plant access restrictions and exposure monitoring consistent with 10 CFR Part 20. The NRC staff finds that these administrative controls are adequate to maintain the increased dose limits within regulatory requirements.

The licensee stated that operational parameters for the various heat exchangers in the CVCS bound the EPU operating conditions. In addition, the licensee stated that the flow rates for the CVCS letdown line and excess letdown line are not affected by EPU conditions. Table 9.2-3 of the EPULR shows that the original design values for heat exchanger performance and letdown line and excess letdown line flowrates bound the revised EPU values for these parameters. This demonstrates that the CVCS will be able to perform its design function following the EPU and is therefore, acceptable to the staff.

Following a LOCA, a variety of acids and bases are produced in containment. The chemical species dissolved in the containment sump water determines the pH value of the containment sump. Cesium hydroxide (CsOH), hydrochloric acid (HCl), hydriodic acid (HI), and nitric acid (HNO_3) are introduced into the containment sump following a LOCA. CsOH and HI directly enter the containment via the RCS. Radiolytic decomposition of cable jacketing produces HCl and HNO_3 is synthesized in the existing radiation field in containment.

In order to prevent dissolved radioactive iodine from being released during the recirculation containment spray injection into the containment, sump water must be maintained in an alkaline (basic) condition. Most of the iodine which leaves the damaged core is in an ionic form which dissolves readily in the sump water. However, some of the iodine converts back to a less soluble elemental form in an acidic environment which results in re-evolution of iodine to the containment atmosphere. The sump pH must be maintained equal to or greater than seven to prevent elemental iodine release to the containment atmosphere following a LOCA.

Following a LOCA, most of the water that fills the containment sump comes from systems that contain boric acid (i.e., RCS, refueling water storage tank) which will result in an acidic sump water pH. In order to maintain the sump pH equal to or greater than seven for 30 days following a LOCA, BVPS-1 and 2 utilize their chemical addition systems which add sodium hydroxide as a buffer. This is consistent with other similarly designed plants.

Conclusion

On the basis of its review, the NRC staff concludes that the while the N-16 dose rates will increase under EPU conditions, the licensee has adequate administrative controls to maintain the dose limits within the requirements of 10 CFR Part 20. Further, the CVCS will continue to perform its key functions at EPU conditions since the heat exchangers and letdown line and excess letdown line will continue to operate within their design limits. Therefore, this is acceptable to the staff.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

SSCs important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. The NRC staff conducted a review of pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures. The staff's review covered (1) the implementation of criteria for defining pipe break and crack locations and configurations, (2) the implementation of criteria dealing with special features, such as augmented ISI programs or the use of special protective devices such as pipe-whip restraints, (3) pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects, and (4) the design adequacy of supports for SSCs provided to ensure that the intended design functions of the SSCs will not be impaired to an unacceptable level as a result of pipe-whip or jet impingement loadings. The staff's review focused on the effects that the proposed EPU may have on items (1) thru (4) above. The acceptance criteria are based on GDC 4, which requires SSCs important to safety to be designed to accommodate the dynamic effects of a postulated pipe rupture. Specific review criteria are contained in SRP Section 3.6.2.

Technical Evaluation

The original structural design basis of BVPS-1 and BVPS-2 required consideration of the dynamic effects resulting from pipe breaks and protective measures from such breaks be incorporated into the design. Through application of LBB technology, which was subsequently allowed by revisions to GDC 4, the need to consider the dynamic effects for the primary reactor coolant loop piping breaks and pressurizer surge line break for BVPS-1 and 2 was eliminated. Following the application of LBB, the governing breaks for BVPS-1 include branch line pipe breaks (BLPBs) in the SI accumulator line on the cold leg and residual heat removal line on the hot leg. For BVPS-2, the application of LBB methodology further eliminates consideration of the dynamic effects resulting from pipe breaks in RCS branch line piping greater than or equal to 6 inches. As such, the BVPS-2 LOCA dynamic analyses were performed for the next most

limiting branch lines: the 4-inch pressurizer spray line on the cold leg and a 3-inch line on the hot legs based on the bounding PORV line size.

In its response dated May 26, 2005, to the NRC staff's RAI, the licensee indicated that the BVPS-1 primary reactor coolant loop piping, components and supports, including the RV and internals, have been evaluated for the EPU condition with consideration of the dynamic effects due to the RSGs. The licensee performed NUPIPE-SWPC thermal, dead load, pressure, seismic and dynamic analyses to account for the branch line piping breaks and the main steam and feedwater piping breaks. The evaluations include the EPU system design parameters, transients and dynamic loads on the major components, nozzles, and supports for the normal operating, upset, and faulted LOCA conditions. The methods, criteria, load combinations used for the EPU and RSG are the existing design basis analyses of record (AOR), specified in BVPS-1 UFSAR Tables 4.1-11 and B.3-5. The calculated stresses and cumulative fatigue usage factors (CUFs) are noted below the code allowable limits. The licensee stated that the BVPS-2 primary reactor coolant piping was bound by existing design basis and therefore was not reanalyzed to consider effects from EPU. Maximum stresses and fatigue usage (CUF) in RCS component supports are unchanged from the current design basis and remain within the code allowable limits.

The methods used to evaluate pipe rupture locations and associated dynamic effects are addressed in the BVPS-1 UFSAR in Section 5.2 and its Attachments A and B, and the BVPS-2 UFSAR in Section 3.6 and following methodology.

For postulation of intermediate pipe break locations for BVPS-2, the following changes to the criteria presented in UFSAR Sections 3.6B2.1.1.2 and 3.6B2.1.2.1 for ASME Code, Section III, Class 2 and 3piping and seismic non-nuclear piping apply.

- Breaks will be postulated at locations where the stresses associated with the normal and upset plant conditions including an OBE event exceed 0.8 (1.8 Sh + SA), as calculated from the sum of Equations 9 and 10, Paragraph NC-3652 of the ASME Code, Section III, for Class 2 and 3 piping.

- The 0.8 (1.8 Sh + SA) criterion is a change from the present BVPS-2 criterion of 0.8 (1.2 Sh + SA). The revised criterion is in accordance with SRP Section 3.6.2, Revision 1 and the Branch Technical Position (BTP) MEB 3-1, Revision 2. The revised criterion used was incorporated in BTP MEB 3-1, Revision 2 and the applicable ASME Code, Section III, Paragraph NC-3652 Winter 1981 addendum and used in the later ASME Code Section III versions. The BVPS-2 calculated stresses and allowables used in the piping analyses where the revised criterion has been applied are consistent with that of ASME Code, Section III 1986, Paragraph NC-3652.

The piping evaluations included an assessment of postulated pipe rupture locations and associated dynamic effects. The piping evaluations demonstrated that the EPU does not impact the existing design basis for postulated pipe rupture locations and associated dynamic effects based on the methods identified and described above. There are no new pipe rupture locations. There is also no increase in pipe whip and jet impingement forces.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to determinations of rupture locations and associated dynamic effects and concludes that the licensee has adequately addressed the effects of the proposed EPU on them. The staff further concludes that the licensee has demonstrated that SSCs important to safety will continue to meet the requirements of GDC 4 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the determination of rupture locations and dynamic effects associated with the postulated rupture of piping.

2.2.2 Pressure-Retaining Components and Component Supports

Regulatory Evaluation

The NRC staff has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the ASME Code, Section III, Division 1, and GDCs 1, 2, 4, 14, and 15. The staff's review focused on the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The staff's review covered (1) the analyses of FIV and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The staff's review also included a comparison of the resulting stresses and CUFs against the code-allowable limits. The NRC's acceptance criteria are based on (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (4) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (5) GDC 15, insofar as it requires that the RCS be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1; and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

2.2.2.1 Nuclear Steam Supply System Piping, Components, and Supports:

The BVPS EPU project included analyses and evaluations for the reactor coolant loop piping and supports, including pressurizer surge line stratification and application of LBB methodology. The purpose of the piping and supports systems including associated equipment review is to evaluate the effects of EPU and to ensure design-basis code compliance.

The licensee evaluated the NSSS piping and supports by reviewing the design-basis analysis against the uprated power condition, with respect to the design system parameters, transients and the LOCA dynamic loads. The evaluation was performed for the main coolant loop (MCL)

and the pressurizer surge line piping systems. The methods, criteria and requirements used in the existing design basis analysis as specified in the BVPS-1 and 2 Updated Final Safety Analysis Reports (UFSARs) are applicable for the power uprate evaluation.

The original structural design basis for BVPS-1 and 2 required consideration of the dynamic effects resulting from pipe breaks and protective measures from such breaks be incorporated into the design. Through application of LBB technology, which was subsequently allowed by revisions to GDC 4, the need to consider the dynamic effects for the primary reactor coolant loop piping breaks and pressurizer surge line break for BVPS-1 and 2 was eliminated. For BVPS-2, the current structural design basis also includes application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in RCS branch line piping greater than or equal to 6 inches. Following the application of LBB, the governing pipe breaks in the design basis of the BVPS-1 RCS are all primary branch lines including the SI accumulator line attached to the cold leg and residual heat removal on the hot leg, and the main steam and feedwater piping attached to the SGs. In its response dated May 26, 2005, to the NRC staff's RAI, the licensee stated that since all branch lines greater or equal to a 6-inch diameter for BVPS-2 were excluded under GDC 4 with appropriate LBB analyses, LOCA hydraulic forces were developed for breaks in the next most limiting branch lines, which were the 4-inch pressurizer spray line on the cold legs and a 3-inch line on the hot legs based on the bounding PORV line size. The forcing function is bounded by the original design-basis main loop pipe breaks.

In its response dated May 26, 2005, to the NRC staff's RAI, the licensee indicated that the BVPS-1 plant-specific primary reactor coolant loop piping, piping components, RSGs, RCPs, and their supports were evaluated for the EPU and RSG conditions using a thee-dimensional NUPIPE-SWPC model. The computer code was used to perform thermal, deadload, pressure, seismic and dynamic time history analyses. The dynamic time history analyses were based on the branch line piping and the main steam and feedwater piping breaks. The licensee indicated that the only changes between the original analysis and the analysis in support of the EPU and the RSGs are: (1) the original primary reactor coolant loop piping mathematical model was converted from the STARDYNE computer code format to the NUPIPE-SWPC computer code input format, (2) the ASME Code Case N–411 damping values, approved for use at BVPS-1, were used in lieu of 2-percent damping for the design-basis earthquake (DBE), and (3) the pipe break loadings were based on EPU conditions with RSGs, instead of pre-uprate conditions with the OSGs. The modal superposition method with 1 percent of critical damping applied at each mode was used in the dynamic analyses, which is consistent with the BVPS-1 design basis for the primary reactor coolant loop systems. The resultant stresses for the reactor coolant loop piping are reported in the EPULR, Table 8.3-1. The results from the NUPIPE-SWPC analyses for the primary reactor coolant loop piping include loads on the major components, nozzles, and supports for the normal operating, upset, and faulted LOCA conditions. The component nozzle loads were reconciled with the final loop stress analysis that included the RSGs. All the results were bounded by the analysis results submitted in the EPULR except for the RCP nozzle loads which are tabulated in Table 4.6.1-2A of the licensee's May 26, 2005, RAI response. The table shows that the maximum upset stresses for the RCP nozzles remain well below the Code allowable stresses and are, therefore, acceptable. For BVPS-2, the primary reactor coolant loop was not reanalyzed to consider effects from EPU, because the EPU loads are bounded by the original design-basis loads, which includes the loadings due to temperature, weight, seismic, reactor coolant branch breaks, and main steam and feedwater line breaks. The stresses and fatigue usage factors are bounded by the original AOR.

The licensee evaluated the BVPS-1 and 2 surge line considering the thermal stratification transients. The inputs to the pressurizer surge line stratification analysis included the NSSS design (PCWG) parameters and revised NSSS design transients for EPU (Section 2.2.1), and the revised design loads for EPU conditions. The analysis is consistent with the original pressurizer surge line stratification AOR. The pipe stresses and fatigue usage factors for the pressurizer surge line stratification were reviewed in accordance with 1986 Edition of the ASME Code, Section III. The results are tabulated in Table 4.5.1-1 of the licensee's October 4, 2004, application. The calculated stresses and CUFs are below the code allowable limits and are, therefore, acceptable.

System operation at EPU conditions may increase piping stress levels, pipe support loads, equipment nozzle loads and supports due to higher operating temperature, pressure and flow rates. The licensee evaluated steam and power conversion piping systems (main steam, extraction steam, condensate, feedwater, heater drains, SG blowdown, circulating water), auxiliary piping systems (river/service water, reactor plant component cooling water, turbine plant component cooling water, fuel pool cooling, AFW) and NSSS-related piping systems (RCS, NSSS equipment supports, quench spray, SI, recirculation spray). NSSS equipment supports include the RV, SG, RCP, and pressurizer supports. The reactor coolant loop piping and supports for BVPS-1 were evaluated in accordance with ANSI B31.1, 1967 Edition, including Summer 1971 Addenda. For BVPS-2 piping systems were evaluated in accordance with ASME Code, Section III, 1971 Edition, up to and including Winter 1972 Addenda for Class 1, 2 and 3 piping, and ANSI B31.1, 1967 Edition, including Summer 1972 Addenda for Class 4 piping. The pipe stress results are provided in Table 8.3-1 and 8.3-2 of the licensee's October 4, 2004, application, and include the piping location loading condition, current stress, EPU stress, allowable stress, and the resulting design margins for EPU. Based on its evaluation, the licensee determined that the BVPS-1 and BVPS-2 piping systems and supports remain within allowable Code limits. The NRC staff concurs with the licensee's conclusion.

On the basis of its review of the licensee's submittal, the NRC staff concurs with the licensee's conclusion that the existing NSSS piping and supports, the primary equipment nozzles, and the primary equipment supports, will remain in compliance with the requirements of the design-bases criteria, as defined in the BVPS-1 and 2 UFSARs, and are, therefore, acceptable for the proposed power uprate.

2.2.2.2 Balance-of-Plant (BOP) Piping, Components, and Supports

The licensee evaluated essential BOP piping systems to assess the impact of the various changes due to uprate and/or due to new branch line pipe break (BLPB) LOCA, and thermal stratification. Besides the RCS piping on the primary side, the SI, extraction steam, condensate, heater drains, SG blowdown, circulating water, river/service water, reactor plant component cooling water, turbine plant component cooling water, fuel pool cooling, AFW, and quench spray were evaluated. Maximum calculated stresses and CUFs for the evaluated BOP piping systems are provided in the Tables 8.3-1 and 8.3-2 of the licensee submittal for the proposed power uprate. The BOP piping and supports for BVPS-1 were evaluated in accordance with ANSI B31.1, 1967 Edition, including Summer 1971 Addenda. For BVPS-2, piping systems were evaluated in accordance with ASME Code, Section III, 1971 Edition, up to and including Winter 1972 Addenda for Class 1, 2 and 3 piping, and ANSI B31.1, 1967 Edition, including Summer 1972 Addenda for Class 4 piping. The calculated stresses and CUFs provided are within the code allowable limits and are, therefore, acceptable.

In its response, dated May 26, 2005, to the NRC staff's RAI, the licensee indicated that the BVPS-1 primary reactor coolant loop piping and supports were evaluated for the EPU conditions with consideration of the effects due to the RSGs. The evaluations include EPU system design parameters, transients, and LOCA dynamic loads. The methods, criteria, load combinations, and requirements used in the EPU evaluations are consistent with the original design-basis AOR, as specified in the BVPS-1 UFSAR Tables 4.1-11 and B.3.5. BVPS-2 primary reactor coolant loop was not reanalyzed to consider effects from EPU, because the EPU loads are bounded by the original design-basis loads, which include the loadings due to temperature, weight, seismic, reactor coolant branch breaks, and main steam and feedwater line breaks. The stresses and fatigue usage factors are bounded by the original AOR.

The licensee also stated that the effects of the increased steam flow in the secondary system (main steam and feedwater piping) due to the power uprate qualification is not specifically performed for effects of vibration due to fluid flow. The original piping was designed to the criteria in the ASME B31.1 (BVPS-1) and ASME Code, Section III (BVPS-2) for seismic, anticipated operating, and transients loads. For the EPU conditions, the piping was re-analyzed and the existing pipe support system was found to be adequate without modifications. The EPU represents an incremental change of flow in the main steam and feedwater piping, which could potentially increase the vibration in these two systems. The licensee indicated that during power ascension of the EPU, the piping in these two systems will be monitored to identify areas with potentially significant changes in vibratory behavior as well as to obtain baseline data in order to determine future changes in vibration characteristics. In addition, the licensee indicated that special emphasis on monitoring for vibration will be placed on branch connections extruding from the main steam and feedwater piping. The licensee also indicated that vibration monitoring and evaluation of the measured data will be in accordance with ASME OM-S/G-2003, Part 3, "Standards and Guides for Operations and Maintenance of Nuclear Power Plants."

The licensee evaluated piping systems such as piping, piping supports, equipment, and equipment supports and nozzles, affected by the increased pipe stress and pipe support loads due to higher operating temperatures, pressures, and flow rates internal to piping, resulting from the EPU conditions, by applying the change factors derived from the heat balance diagrams and calculations of the pre-EPU and EPU system operating data. The thermal, pressure, and flow rate change factors were used in determining the acceptability of piping systems for EPU conditions. For change factors less than or equal to 1.0 or where the pre-EPU condition envelopes or equals the post-EPU condition, the piping system was judged to be acceptable for EPU conditions. In its response, dated May 26, 2005, the licensee indicated that for all change factors greater than 1.0, a detailed assessment was performed. The critical pipe stress levels of all affected piping systems are presented in Table 8.3-1 and 8.3-2. The licensee concludes that the results of the BVPS-1 and BVPS-2 analyses are within the code allowable limits.

With regard to the FIV at EPU operation, in its EPU license amendment request and RAI responses, the licensee described the vibration monitoring program to be implemented at BVPS-1 and 2 during EPU power ascension and operation. The licensee stated that vibration monitoring will be performed to identify the sources of vibration in plant systems, and to determine appropriate corrective actions to eliminate or minimize the vibrations.

The licensee indicated that the vibration monitoring program for BVPS-1 and 2 during EPU power ascension and operation will apply the guidance provided in ASME OM Code, Part 3. Prior to EPU power ascension, the licensee indicated that it will perform baseline walkdowns to identify plant systems and components susceptible to potential vibration. The licensee also indicated that it will establish a vibration baseline for these systems and components, and will continue to monitor the systems and components during EPU power ascension to identify any potentially significant changes in vibration levels.

The licensee noted that it has reviewed industry operating experience when establishing the vibration monitoring plan for BVPS-1 and 2. The licensee noted that special emphasis is placed on monitoring vibration of the branch lines connected to the main steam and feedwater piping. Further, the licensee indicated that it has verified that BVPS-1 and 2 do not contain feedwater sample probes similar to those that have failed under EPU flow conditions at other plants, and that thermowells used for temperature measurement at BVPS are designed to accommodate the EPU flow velocity.

The licensee stated that it will control the EPU power ascension at BVPS-1 and 2 by procedure. During EPU power ascension, the licensee will collect plant data and conduct system walkdowns at each 2.5-percent step in power level. In its application, the licensee noted that system engineers will make vibration observations of piping and components, and will collect more precise vibration measurements using instrumentation as needed. The licensee also noted that it will evaluate the plant data against acceptance criteria. After the data are evaluated and resolved, the licensee plans to continue the power ascension. If any vibration measurements or observations are determined to be a safety concern, the licensee committed to reduce the power level of the affected BVPS unit until vibration levels are within acceptable limits. The licensee clarified that power ascension will not be reinitiated until the vibration issue is resolved.

The NRC staff considers the vibration monitoring program being established for EPU power ascension and operation at BVPS-1 and 2 to be acceptable in consideration of the licensee's emphasis on FIV issues.

Based on its review of the licensee’s evaluation regarding structural integrity, including consideration of FIV for BOP and non-Class 1 piping components and supports at EPU conditions for both BVPS-1 and 2, the NRC staff finds the scope and analysis methodology of the licensee's evaluation to be acceptable based on the review criteria documented in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1.

2.2.2.3 Reactor Vessel (RV) and Supports

The licensee evaluated the RV for the effects of the revised design conditions provided in Table 2.1.2-1 of the licensee’s October 4, 2004, application for the core power level of 2900 MWt. The evaluation was performed for the limiting vessel locations with regard to stresses and CUFs in each of the regions, as identified in the RV stress reports for the core power uprated conditions. The regions of the RVs affected by the power uprate include the RPV (main closure head flange, closure studs, and vessel flange), CRDM housing, outlet and inlet nozzles, vessel wall transition, core support pads, bottom head juncture, bottom head instrumentation tubes, and core support guides. In its amendment request, the licensee indicated that the evaluation of the RV was performed in accordance with the ASME Code,

Section III, 1968 Edition with addenda through Summer 1970 and the 1974 Edition for faulted conditions for BVPS-1, and the ASME Code, Section III, 1971 Edition with Addenda through Summer 1972 and the 1974 Edition for faulted conditions for BVPS-2. The results indicate that the maximum primary plus secondary stresses for all the RV critical locations other than the closure studs are within the code allowable limits. The licensee stated that the CUF for the closure studs exceeds the 1.0 limit when all the 18,300 occurrences of plant (Unit) loading and unloading transients are used in the calculations for BVPS-1and BVPS-2. However, the CUF can be reduced below the 1.0 limit, if the number of occurrences is reduced to 10,400 cycles for BVPS-1 and 14,000 for BVPS-2. In its response to NRC staff's RAI, Section N7 of the licensee's May 26, 2005, RAI response, the licensee demonstrated that the number of unit loading and unloading transients experienced through October 15, 2003, in addition to anticipated transients throughout the licensed period are low compared to the allowable design loadings. The licensee concluded that the stresses and CUFs for the reactor vessel critical locations remain below the allowable ASME Code limits.

To perform the RPV LOCA analyses for BVPS-1 and 2, a three-dimensional nonlinear finite element model of the RPV system was developed using the WECAN computer code. The model represents the dynamic characteristics of the RV and its internals in the six geometric degrees of freedom. The WECAN computer code (or predecessor codes) has been used for this analysis since the original plant design. In order to evaluate the impact of changes in RCS condition on the dynamic response of the RPV system, LOCA analyses were performed to generate core plate motions and the RV/internals interface loads. Since LBB methodology eliminated consideration of breaks in the main coolant loop piping and the pressurizer surge line pipping, the WECAN code was used to perform the dynamic time history analyses due to the BLPBs. The hydraulic LOCA forces used in the reactor vessel LOCA analysis are for breaks in the 12-inch accumulator line (cold leg) and the 14-inch residual heat removal line (hot leg) for BVPS-1 and for breaks in the 4-inch line (cold leg) and the 3-inch line (hot leg) for BVPS-2. Forcing functions for EPU conditions are based on the RCS loop branch line breaks which are bounded by the original design basis loads resulting from the large primary loop break prior to the application of LBB methodology. Therefore, the BVPS-1 and BVPS-2 primary coolant loop piping original design basis are bounding for the EPU conditions.

On the basis of its review, the NRC staff concurs with the licensee's conclusion that the current design of the reactor vessel continues to be in compliance with the licensing basis codes for the proposed power uprate condition.

2.2.2.4 Control Rod Drive Mechanism

The pressure boundary portion of the control rod drive mechanism (CRDM) and the capped latch housing (CLH) are those exposed to the vessel/core inlet fluid. The CRDMs and CLHs are affected by the reactor coolant pressure, the vessel outlet temperature, and the NSSS design transients. The licensee evaluated the adequacy of the CRDMs and CLHs by reviewing the BVPS-1 and 2 original AOR. The evaluation for the BVPS-1 CRDMs was performed in compliance with the requirements of the ASME Code, Section III, "Nuclear Vessels," 1971 Edition, up to and including the 1971 Winter Addenda and the 1971 Edition up to and including the 1973 Winter Addenda for BVPS-2.

On the basis of its evaluation, the licensee determined that the transient conditions for the power uprate are unchanged from the original design basis in the AOR. The number of

transient occurrences are not changed for the power uprate. The reactor coolant pressure remains unchanged for the proposed power uprate. The vessel outlet temperature of 617 EF for the EPU was enveloped by the original design temperature of 650 EF. Where the original design assumptions did not envelop the proposed power uprate condition, the licensee performed an additional analysis for the upper threaded joint area and a fatigue analysis for the CRDMs and CLH cap. The upper joint configuration analysis was performed in compliance with the requirements of the ASME Code, Section III, 1968 Edition, up to and including the 1969 Winter Addenda and the CLH cap fatigue analysis was performed in compliance with the 1974 Edition of the ASME Code, Section III, up to and including the 1975 Winter Addenda. For BVPS-2, evaluations were also performed for replacement of part length CRDMs and the acceptability of a spare CRDM in compliance with the 1971 Edition of the ASME Code, Section III, up to and including the 1973 Winter Addenda. The resultant stresses and CUFs for the additional analysis are summarized in Section 4.4.4 of the EPULR. The calculated stresses and CUFs are less than the Code allowable limits and are, therefore, acceptable.

Because the EPU transient conditions are either enveloped by the AOR or supported by additional licensee analyses that demonstrate that the resultant stresses and CUFs are less than the Code allowable limits, the NRC staff concurs with the licensee's conclusion that the CRDMs will maintain their structural and pressure integrity for the proposed power uprate.

2.2.2.5 Steam Generators and Supports

In its amendment request dated October 4, 2004, the licensee indicated that the BVPS-1 Model 51 OSGs will be replaced with Westinghouse Model 54F RSGs prior to operation of BVPS-1 at EPU conditions. The licensee further stated that the RSGs are being designed and analyzed for the PCWG parameters, NSSS design transients, and LOCA forces for 2910 MWt NSSS power as defined in Sections 2.1, 2.2.1, and 5.7 of the licensee's submittal. A thermal-hydraulic analysis and ASME Code, Section III structural analysis was performed for the RSG components also. The licensee indicated that the code and code edition used as the basis for acceptability of the structural analysis is the 1989 Edition of the ASME Code, Section III, "Rules for Construction of Nuclear Power Plant Components." The licensee states that the design and analysis for the Model 54F RSGs performed for the NSSS power of 2910 MWt bound and support operation at the NSSS power of 2697 MWt, thus supporting the staged implementation of EPU at BVPS-1. An ASME Code Design Report is being prepared using the PCWG parameters from Section 2.1.1, the NSSS design transients from Section 2.2.1, and the LOCA hydraulic forces from Section 5.7 of the EPULR. The RSGs are being analyzed to show that tube CUFs meet the requirements of the 1989 Edition of the ASME Code, Section III. The licensee noted that any hardware changes and additions that might be required in the future would be designed and analyzed to meet applicable ASME Code requirements.

For BVPS-1, the EPU LAR No. 302 and the RSG LAR No. 320 report the results of the structural analyses performed for the reactor coolant loop and loop components (i.e., RV and internals, RCPs, loop stop isolation valves), except for the RSGs. The analyses reported in these LARs incorporate EPU conditions with the Model 54F RSGs. However, the structural analyses for the RSG components were not included in the EPU and RSG LARs since these analyses were still in process when the subject LARs were prepared and submitted to the NRC.

As noted by the licensee, the structural analyses for the RSG components were still in process when preparing its response dated May 26, 2005, to the NRC RAI of March 11, 2005. The calculated stresses and CUFs for critical RSG components and FIV evaluation results were provided later in a licensee's transmittal dated December 2, 2005. The NRC staff finds them to be acceptable since they are within the Code allowable limits.

In response to the NRC staff's RAI on evaluation of calculated stress and CUFs for the RSGs shell, nozzles and internals, and U-tubes, the licensee stated that the stress information is being generated as part of the design process and the information will be included in the Design Stress Report that will be completed prior to operation but after the RSGs are manufactured so that as-built dimensions can be assessed. The licensee performed analysis to evaluate the RSG tube bundle and support system (including flow distribution baffle, tube support plates, and anti-vibration bars) for potential vibration and wear from flow induced vibrations. Potential sources of tube excitation considered in the evaluation included primary fluid flow within U-tubes, mechanically-induced vibration, and secondary fluid flow on the outside of the tube. Primary fluid flow and mechanically-induced vibration effects were considered to be negligible during normal operation. The primary source of potential tube degradation due to vibration is from the hydrodynamic excitation by the secondary fluid on the outside of the tubes. The potential tube vibration mechanisms due to hydrodynamic excitation by the secondary fluid on the outside of the tubes are vortex shedding, turbulence, and fluidelastic vibration. On the basis of its RSG analyses, the licensee concluded that the calculated fluidelastic stability ratios are within acceptance criteria, and the displacements and bending stresses from FIV due to vortex shedding and turbulence are small.

Because the calculated stresses and CUFs for critical RSG components and FIV evaluation results remain within Code allowable limits and because the displacements and bending stresses from FIV due to vortex shedding and turbulence are small, the NRC staff concludes that the RSGs at BVPS-1 are acceptable for the proposed EPU.

The licensee analyzed the BVPS-2 Model 51M OSGs at EPU conditions in the areas of thermal-hydraulic performance, structural integrity, U-bend fatigue, hardware changes and additions (repair hardware), tube wear, tube repair limit, and tube degradation. Evaluation to assess the structural integrity of the OSGs was performed at the EPU power level with steam generator tube plugging (SGTP) in the range of 0 to 22 percent. The NSSS design transients in Section 2.2.1 of the EPULR were used to generate scaling factors with respect to the original stress report results.

In the thermal-hydraulic evaluation, the licensee considered the effects of moisture carryover, hydrodynamic instability, and local dryout of tube walls/departure from nucleate boiling (DNB). From the evaluations, the licensee determined that the thermal-hydraulic operating characteristics for the EPU are acceptable and there are no concerns of thermal performance deficiency, excessive moisture carryover, hydrodynamic instability or local dryout of tube walls.

The licensee evaluated the structural integrity of the SG components for the increase in the NSSS power by 8 percent above the current NSSS power level of 2689 MWt. The seismic and dead weight loads are not affected by the power uprate and remain unchanged from the AOR. The critical components considered in the EPU (divider plate, tubesheet & shell junction, tube-to-tubesheet weld, tubes, main feedwater nozzle, secondary manway bolts, and steam nozzles) were evaluated for the: 1) EPU conditions, 2) cold overpressure mitigation system (COMS)

transient, and 3) coastdown transient. A primary-to-secondary pressure differential evaluation was also performed at normal and upset design conditions. The maximum range of primary-plus-secondary stresses were compared to the corresponding $3S_m$ limits. For situations where these limits were exceeded, a simplified elastic-plastic analysis was performed per NB 3228.3 of the ASME Code, Section III. The stress and CUF are tabulated in Table 4.7.2.2-2 of WCAP-16307-P. The licensee evaluated the structural integrity of the SG components for the EPU in accordance with the 1971 Edition of the ASME Code, Section III, up to and including the 1972 Summer Addenda. The results of the evaluation showed that all components analyzed meet ASME Code allowable limits and are, therefore, acceptable.

As noted in Table 4.7.2.2-2 of the EPULR, the U-bend fatigue and RG 1.121 evaluations were done separately due to the EPU. Addressing unsupported U-bend tubes, the licensee determined under the most limiting EPU operating conditions that up to six tubes from BVPS-2 could require removal from service as tabulated in Table 4.7.2.3-2. Tubes requiring preventive action will be removed from service using sentinel plugs, or cable tube dampers could be installed over plugs.

In its response to the NRC staff's RAI, the licensee provided the evaluation for the effects of FIV on the steam dryer/separator due to the increase in steam flow for the EPU. For BVPS-1 and 2, the SGs use a secondary moisture separator which consists of a multi-vanes assembly to make up the dryer. The flow velocities associated with the steam dryer/separator are about 3 to 4 feet per second. The separator assembly is structurally rugged. The potential for FIV of the steam separator is minimized due to its high stiffness (resulting in a high natural frequency) combined with low velocity of the passing flow. In addition, past inspections performed for SG secondary moisture separators on operating PWR plants have not found indications due to FIV fatigue. Based on its evaluation, the licensee concluded that the steam dryers/separators are not affected for the proposed power uprate regarding the potential for FIV.

Addressing RG 1.121 considerations, it is shown for both the RSGs in BVPS-1 and the OSGs in BVPS-2, that the structural limits calculated during EPU conditions support a tube plugging limit of 40 percent allowable wall loss such that NEI 97-06, Revision 2 performance criteria continue to be met.

Based on the above, the NRC staff concurs with the licensee's conclusion that the RSGs at BVPS-1 and the OSGs at BVPS-2 will continue to maintain their structural and pressure boundary integrity, remain in compliance with the code of record specified in the UFSAR and are, therefore, acceptable for the proposed 8-percent EPU.

2.2.2.6 Reactor Coolant Pumps and Supports

The licensee reviewed the existing design basis analyses of the BVPS-1 and 2 Model 93A RCPs and limiting pressure boundary components which are affected by the reactor coolant pressure, SG outlet temperature and primary side cold leg NSSS design transients in accordance with the generic component design reports and the ASME Codes listed in Tables 4.6.1-2A and 4.2.1-2B of the EPULR. The input parameters used to perform the analysis and evaluations for EPU included the original NSSS design parameters and transients, EPU Power Capability Working Group (PCWG) parameters (Section 2.1.1 of the EPULR) along with EPU NSSS design transients (Section 2.2.1 of the EPULR), and the current design-basis

evaluation for the RCPs. The critical components affected by the EPU include casing, main flange bolts, and discharge and suction nozzle.

EPU PCWG parameters (vessel inlet temperature and reactor coolant pressure) and NSSS design transients were compared to the design input of each component as defined by the component's original evaluation for BVPS-1 and 2. RCPs were accepted if the design inputs from the AOR remain bounding and applicable to the design input developed for the EPU. For BVPS-1, design input not enveloped were evaluated in accordance with ASME Code, Section III, 1968 Edition, through the 1970 Winter Addenda and 1971 Edition, through the 1972 Winter Addenda. For BVPS-2, design input not enveloped were evaluated in accordance with ASME Code, Section III, 1968 Edition, through the 1970 Winter Addenda and 1974 Edition, through the 1975 Summer Addenda. A summary of the stress intensity and CUFs for the limiting RCP pressure boundary components at EPU conditions is provided in Tables 4.6.1-2A and 4.6.1-2B of the EPULR.

The maximum stresses for the RCP limiting components and the CUFs shown in Tables 4.6.1-2A and 4.6.1-2B of the EPULR are within the Code allowable limits and therefore, acceptable for the proposed EPU. The licensee also evaluated the RCP motors and found them to be acceptable for the proposed EPU operation.

On the basis of its review, the NRC staff concurs with the licensee's conclusion that the current RCPs and supports at BVPS-1 and 2, will continue to maintain their structural and pressure boundary integrity and remain in compliance with the code of record specified in the UFSAR and are, therefore, acceptable for the proposed 8-percent EPU.

2.2.2.7 Pressurizer and Supports

The licensee evaluated the structural adequacy of the pressurizer and components (spray nozzle, upper head, surge nozzle, lower head, heater well, support skirt and flange, safety and relief nozzles, instrument nozzle, immersion heater, seismic support lug and shell buildup trunnion) affected by pressure, surges through surge nozzle, spray flow through the spray nozzle and steam temperature differences, for operation at the uprated conditions. The licensee indicated that seismic analysis and non-pressure boundary component evaluations were considered to be unaffected by the EPU project. The analysis also addressed pressurizer insurge/outsurge transients consistent with the analytical assumptions employed in the evaluation of pressurizer transients [8], [9], and [17].

The evaluation was performed by comparing the key parameters in the current design basis pressurizer stress report, which were performed to the requirements of the 1965 Edition of the ASME Code, Section III, up to and including Winter 1966 Addenda for BVPS-1 and 1971 Edition, Summer 1972 Addenda for BVPS-2, against the revised EPU PCWG parameters provided in Section 2.1.1 of the EPULR and the EPU NSSS design transients provided in Section 2.2.1 of the EPULR. For BVPS-1, the critical spray nozzle location was evaluated based on the 1989 Edition of the ASME Code, Section III, due to the impact of changes to the spray nozzle transients.

Analytical models of various sections of the pressurizer were subjected to pressure loads, external loads (such as piping loads), and thermal transients. Input parameters in Section 2.1.1 of the EPULR for the EPU conditions were reviewed and compared to the design input

considered in the original pressurizer stress reports. In cases where revised input parameters were not bounded, the licensee performed additional pressurizer structural analysis and evaluations. Revised CUFs were calculated and summarized in Tables 4.8-1 (excluding insurge/outsurge operating transients) and 4.8-3 (considering insurge/outsurge operating transients). Primary plus secondary stress intensity ranges, excluding insurge/outsurge operating transients, are summarized in Table 4.8-2 of the licensee's submittal. The NRC staff finds that the calculated stresses and CUFs for the limiting pressurizer locations at the uprated condition are less than the Code allowable limits or are justified by simplified elastic-plastic analysis in accordance with Paragraph NB-3228.3 of Section III of the ASME Code, and are, therefore, acceptable.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of pressure-retaining components and their supports. For the reasons set forth above, the staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these components and their supports. Based on the above, the staff further concludes that the licensee has demonstrated that the pressure-retaining components and their supports will continue to meet the requirements of 10 CFR 50.55a, GDCs 1, 2, 4, 14, and 15 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

2.2.3 Reactor Pressure Vessel (RPV) Internals and Core Supports

Regulatory Evaluation

RPV internals consist of all the structural and mechanical elements inside the RV, including core support structures. The NRC staff reviewed the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for the reactor internals for normal operation, upset, emergency, and faulted conditions. These include pressure differences and thermal effects for normal operation, transient pressure loads associated with LOCAs, and the identification of design transient occurrences. The NRC staff's review covered (1) the analyses of flow-induced vibration for safety-related and non-safety-related reactor internal components and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The staff's review also included a comparison of the resulting stresses and CUFs against the corresponding Code allowable limits. The NRC's acceptance criteria are based on (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; and (4) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

The licensee evaluated the effect of the power uprate on the RV internals (RVIs) in Section 4.2 of the BVPS-1 and 2 EPULR. The RVIs evaluated for the proposed power uprate consist of core support and internal structures, and fuel and CRDMs. Core support assemblies, which provide support of the reactor core, include the upper and lower core plate, upper and lower support columns, upper and lower support plate, core barrel and alignment and guidance structure components that includes the radial support system, head-vessel alignment pins, upper core plate alignment pins in the core barrel assembly, and special temporary guide studs attached to the vessel. The core barrel provides a flow boundary for the reactor coolant. The function of the RVI components is to support and orient the reactor core fuel assemblies and control rod assemblies, absorb control rod dynamic loads, and transmit these and other loads to the RV. They also direct coolant flow through the fuel assemblies (core), to provide adequate cooling flow to the various internals structures, and to support in-core instrumentation. In its evaluation, the licensee reviewed the effects of the revised thermal-hydraulic system (including system pressure losses, bypass flow, upper head fluid temperature, hydraulic lift forces, and baffle joint momentum flux and fuel rod stability), FIV, structural evaluation of reactor internal components (upper and lower core plates, lower core support plate, lower support columns, core barrel assembly, lower radial supports, upper core plate alignment pins, upper support assembly, and baffle/former bolts), rod control cluster assembly (RCCA) drop time and LOCA and seismic evaluation. In the licensee's structural analysis, the fuel considered is a full core of Robust Fuel Assembly (RFA) fuel (including RFA-2) with intermediate flow mixing (IFM) grids and thimble plugs removed. The design of the BVPS-1 and 2 reactor internals was evaluated in accordance with Westinghouse's internals criteria which is the code of record. The criteria contained therein, are similar to Subsection NG of the ASME Code, Section III.

The licensee used the THRIVE computer code to perform its evaluation of the thermal-hydraulic system by solving the mass and energy balances for the reactor internals fluid system. The THRIVE code computes the vessel pressure drops, core bypass flow, RPV fluid temperature, hydraulic lift forces and baffle joint momentum flux within the RVIs and core. Based on the thermal-hydraulic evaluation, the licensee concluded that the design maximum core bypass flow value can be maintained, the reactor internals will remain seated and stable for the EPU RCS conditions, and the baffle joint momentum flux margins remain acceptable. The thermal-hydraulic evaluation results are summarized in Section 4.2.4 and Tables 4.2-2 through 4.2-4 of the licensee's October 4, 2004, application.

In its response dated May 26, 2005, to the NRC staff's RAI, the licensee indicated that the evaluation of the FIV was performed at EPU conditions to determine the impact of EPU on the BVPS-1 and 2 RVI components. The reactor internals that the licensee considered in its evaluation include the lower internals assembly (core barrel, thermal shield support flexures, thermal shield support bolts, and dowel pins), lower support plate, upper internals guide tubes, and upper support plate. The licensee concluded that based on the FIV evaluation at EPU conditions, the results are acceptable and there is no adverse impact on the structural integrity of the BVPS-1 and 2 reactor internal components. The calculated and allowable stresses for FIV are summarized in Table 14 of the licensee's May 26, 2005, RAI response. As shown in the table, the calculated stresses remain well below the allowable stresses and are, therefore,

acceptable. The staff concurs with the licensee's conclusion that the RVIs will retain their structural integrity at the EPU conditions.

Structural evaluations of reactor internal components were also performed to demonstrate that the structural integrity of the reactor components is not adversely affected directly by the change in RCS conditions and/or by secondary effects of the change on reactor thermal-hydraulic or structural performance. The licensee evaluated several key reactor internal components at the EPU RCS conditions, including the baffle-barrel region and the lower and upper core plate.

The results of the licensee's evaluation are summarized in Section 4.2.4 and Table 4.2-5 of the licensee's October 4, 2004, application. Stress intensities in the RVI components resulting from the incorporation of revised input loads associated with EPU were shown to be less than the Code allowable limits. Cumulative fatigue usage was shown to be less than 1.0 for the lower and upper core plate. The licensee concluded that the RVI components will continue to satisfy the Code allowable limits. Based on the stress intensities of the RVI components being less than the code allowable limits, and the cumulative fatigue usage for the upper and lower core plate being less than 1.0, the NRC staff concurs with the licensee's conclusion that the RVIs will retain the structural integrity at the EPU conditions.

On the basis of its evaluation, the licensee determined that the estimated RCCA drop time with seismic allowance is bounded by the original design basis in the AOR. Because the estimated RCCA drop times are bounded by the original design basis in the AOR, the NRC staff finds that the effect of the EPU on RCCA drop times is acceptable.

Based on its review of the RAI response and the licensee's evaluation of the effect of the power uprate on the RVIs structural analysis and integrity, the NRC staff concludes that the licensee's evaluation has adequately demonstrated that the RVIs will safely withstand the normal operating plus upset and faulted conditions that include the effects of the SG replacement plus the proposed EPU.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of reactor internals and core supports and concludes that the licensee has adequately addressed the effects of the proposed EPU on the reactor internals and core supports. The staff further concludes that the licensee has demonstrated that the reactor internals and core supports will continue to meet the requirements of 10 CFR 50.55a, GDCs 1, 2, 4, and 10 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the design of the reactor internals and core supports.

2.2.4 Safety-Related Valves and Pumps

Regulatory Evaluation

The NRC staff's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME Code and within the scope of Section XI of the ASME Code and the ASME *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code), as applicable. The staff's review focused on the effects of the proposed EPU on the

required functional performance of safety-related valves and pumps at BVPS. The review covered impacts that the proposed EPU might have on the licensee's motor-operated valve (MOV) programs related to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," and GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves." The review addressed the performance of power-operated valves as discussed in GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." The staff also evaluated the licensee's consideration of lessons learned from the MOV program and the application of those lessons learned to other safety-related power-operated valves. The NRC's acceptance criteria are based on the Inservice Testing (IST) requirements in 10 CFR 50.55a(f), and the applicable GDCs in 10 CFR Part 50, Appendix A. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6.

Technical Evaluation

The NRC staff conducted a technical evaluation of the licensee's request submitted on October 4, 2004, to operate BVPS-1 and 2 at EPU conditions. The staff provided RAIs to the licensee with regard to the performance of safety-related pumps and valves under EPU conditions, as well as other areas of review. The licensee submitted responses to the NRC staff's RAIs in letters dated May 26 and December 2, 2005.

The NRC staff reviewed the licensee's assessment of the impact of EPU conditions on safety-related pumps and valves in the NSSS systems at BVPS. The NSSS systems at BVPS include the RCS, CVCS, residual heat removal system, and SI system. The performance of most safety-related pumps and valves in the NSSS systems at BVPS are sufficient for system operating pressures, flow rates, and pump head performance under normal operating conditions, and postulated accidents and transients. The licensee indicated that the charging/SI pumps are being modified to improve their high head performance and flow rate.

The NRC staff reviewed the licensee's assessment of the impact of EPU conditions on safety-related pumps and valves in the BOP systems at BVPS. The BOP systems at BVPS include the main steam system, condensate and feedwater system, AFW system, service water system, component cooling water system, and spent fuel pool cooling and cleanup system. Flow and other system parameters will increase in some BOP systems under EPU operation. The licensee described applicable modifications and adjustments to the safety-related pumps or valves in these plant systems. For example, the licensee will install new trim in the feedwater regulating valves (FRVs) in BVPS-1 and replace the FRVs in BVPS-2 to provide the necessary flow and pressure at EPU conditions. The licensee is also installing fast-acting main feedwater isolation valves (MFIVs) in BVPS-1 similar to those in BVPS-2.

The NRC staff reviewed the licensee's assessment of individual safety-related valves addressed in plant programs at BVPS, including those implemented in response to GL 89-10, GL 95-07, and GL 96-05. During the review of the GL 89-10 program at BVPS, the staff previously conducted several inspections of the safety-related MOV program at BVPS, and closed its GL 89-10 review based on the findings from those inspections. As described in an SE dated November 3, 1999, the staff reviewed and accepted the licensee's actions at BVPS described in submittals in response to GL 95-07. In an SE dated February 22, 2000, the staff described its acceptance of the MOV program being implemented at BVPS in response to GL 96-05 based on information submitted by the licensee. In response to NRC staff questions, the licensee provided its assessment with specific examples of the potential impact of EPU

conditions on safety-related valves in BVPS programs. In particular, the BVPS calculations for MOVs in the GL 89-10 and GL 96-05 programs were sufficiently conservative to encompass EPU conditions. The BVPS calculations for power-operated valves in the GL 95-07 program also bounded EPU conditions. Further, the air-operated valve (AOV) program at BVPS is consistent with the industry-wide Joint Owners' Group AOV Program.

In response to NRC questions during the EPU license amendment review, the licensee described the evaluation and actions, with particular examples, to demonstrate the capability of safety-related pumps, power-operated valves, check valves, and safety and relief valves in the IST Program at BVPS to accommodate operating requirements at EPU conditions. For example, the licensee installed new fast-acting MFIVS, modified the high-head SI pumps, and adjusted tolerance settings for the main steam safety valves (MSSVs) and reactor coolant pressurizer safety valves (PSVs). The licensee is revising the IST program procedures at BVPS to incorporate the plant modifications in support of EPU operation.

A specific issue which the NRC staff reviewed relates to the capability of the PSVs to discharge liquid and adequately reseat for a spurious SI actuation. The specific issue which the staff evaluated in this regard is whether the PSVs could reasonably be expected to reseat in order to prevent the spurious SI actuation (a Condition II event) from causing a stuck-open PSV (a condition III event). This issue is further discussed in NRC Regulatory Issue Summary (RIS) 2005-29. While the PSVs are qualified to discharge steam, if the valves discharge liquid having a temperature low enough, they may not reseat properly. Based the licensee's analysis, during the spurious SI event, the PSVs would be required to discharge steam followed by high temperature liquid after the pressurizer fills. The licensee provided plots of the pressurizer water temperatures for this event which indicate that the minimum temperature of the discharged liquid for both BVPS-1 and 2 is approximately 620 EF. To evaluate the capability of the valves to discharge and reseat, the staff reviewed the available data from the full flow tests performed during the EPRI test program in 1981 for the specific PSV models representative of those installed at BVPS-1 and 2. The licensee also used the methodology contained in Topical Report WCAP-11677, and determined that the minimum acceptable liquid temperature for which the PSVs are expected to successfully discharge and reseat is less than the minimum expected temperature for the spurious SI event for BVPS-1 and 2. The staff agrees that both the minimum expected liquid discharge temperature and the minimum acceptable liquid temperature have been conservatively calculated. Therefore, the staff has determined that, for purposes of preventing the occurrence of a more serious Condition III event, there is reasonable assurance that the PSVs would adequately discharge and reseat following a spurious SI actuation. A consideration in making this finding is that, in the unlikely event of a stuck-open PSV, the ECCS is fully capable of mitigating the resulting LOCA.

In summary, the NRC staff reviewed the licensee's assessment of the performance of safety-related pumps and valves at BVPS under EPU conditions, including the specific examples discussed in the EPU request and RAI responses. From its review, the staff determined that the licensee's assessment of safety-related pumps and valves at BVPS for EPU conditions was appropriate in light of operating experience and regulatory guidance.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's assessment of the functional capability of safety-related valves and pumps at BVPS under EPU conditions. Based on its review, the staff

determined that the licensee has adequately addressed the effects of the proposed EPU on safety-related pumps and valves. The staff concludes that the licensee has demonstrated that safety-related valves and pumps at BVPS will continue to meet the requirements of 10 CFR 50.55a(f) and the applicable GDCs in 10 CFR Part 50, Appendix A, following implementation of the proposed EPU.

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

Regulatory Evaluation

Mechanical and electrical equipment covered by this section includes equipment associated with systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal. Equipment associated with systems essential to preventing significant releases of radioactive materials to the environment are also covered by this section. The NRC staff's review focused on the effects of the proposed EPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated with pipe-whip and jet impingement forces. The primary input motions due to the safe shutdown earthquake (SSE) are not affected by an EPU. The NRC's acceptance criteria are based on (1) GDC 1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 30, insofar as it requires that components that are part of the RCPB be designed, fabricated, erected, and tested to the highest quality standards practical; (3) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (4) 10 CFR Part 100, Appendix A, which sets forth the principal seismic and geologic considerations for the evaluation of the suitability of plant design bases established in consideration of the seismic and geologic characteristics of the plant site; (5) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (6) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (7) 10 CFR Part 50, Appendix B, which sets quality assurance requirements for safety-related equipment. Specific review criteria are contained in SRP Section 3.10.

Technical Evaluation

The current structural design basis of BVPS-1 and 2 includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping and the pressurizer surge line piping. For BVPS-2, the current structural design basis also includes application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in RCS branch line piping greater than or equal to 6 inches. Following the application of LBB, the governing pipe breaks in the design basis of the BVPS-1 RCS are all primary branch lines including the SI accumulator and residual heat removal, and the main steam and feedwater piping attached to the SGs. For BVPS-2 the 4-inch pressurizer spray line on the cold legs and a 3-inch line on the hot legs, based on the bounding PORV line size, were considered in the design basis for breaks.

The licensee has stated that the design-basis seismic analysis is not affected by the EPU, therefore, the seismic qualification of essential equipment remains unchanged. In addition, the original design basis for dynamic loads was based on postulated main loop piping breaks which are bounding for the EPU LOCA dynamic loads due to BLPBs for both BVPS-1 and 2. As a result of the pipe stress analyses, the licensee did not identify any new pipe break locations and therefore, the jet impingement and pipe whip restraints remain unaffected by the power uprate. Because the design-basis seismic analysis and seismic qualification of essential equipment are unaffected by the proposed EPU, as are the jet impingement and pipe whip restraints, the NRC staff concurs with the licensee's conclusion that the current design-basis analyses for the seismic and dynamic qualification of safety-related equipment remain adequate for the proposed power uprate.

Conclusion

The NRC staff has reviewed the licensee's evaluations of the effects of the proposed EPU on the qualification of mechanical and electrical equipment and concludes that the licensee has (1) adequately addressed the effects of the proposed EPU on equipment and (2) demonstrated that the equipment will continue to meet the requirements of GDCs 1, 2, 4, 14, and 30; Appendix A to 10 CFR Part 100; and 10 CFR Part 50, Appendix B, following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the qualification of the mechanical and electrical equipment.

2.3 Electrical Engineering

2.3.1 Environmental Qualification (EQ) of Electrical Equipment

Regulatory Evaluation

The term "environmental qualification" applies to equipment that must remain functional during and following design-basis events. The NRC staff's review covers the environmental conditions which could affect the design and safety functions of electrical equipment including instrumentation and control. The staff's review verifies compliance with the acceptance criteria, thus ensuring that the equipment continues to be capable of performing its design safety functions under all normal environmental conditions, anticipated operational occurrences, and accident and post-accident environmental conditions. Acceptance criteria are based on 10 CFR 50.49 as it relates to specific requirements regarding the qualification of electrical equipment important to safety that is located in a harsh environment. Specific review criteria are contained in SRP Section 3.11.

Technical Evaluation

The post-EPU qualification of EQ equipment was evaluated to ensure that environmental parameters and anticipated environmental increases do not adversely affect the capability of safety-related equipment to perform their intended safety function. The following discussion summarizes the qualification parameters for change due to the EPU and the resulting impact on equipment qualification.

For normal and accident pressure inside and outside containment, pressure effects on EQ were evaluated by comparison of the revised pressures to the current qualification pressure requirements. For normal temperature, there are no post-EPU changes to the maximum normal operating temperatures inside or outside the containment. For accident temperatures inside and outside containment, the temperature calculations generated temperature profiles that were compared to the EQ profiles and were verified to be qualified by the equipment qualification test report data. The normal and accident radiation inside and outside containment was reviewed and no change was identified for EPU operation. Electrical component qualifications are not impacted by the increased normal and accident radiation environments following the EPU implementation.

Conclusion

The NRC staff has reviewed the licensee's submittal of the effects of the proposed power uprate on the EQ of the electrical equipment and concludes that electrical equipment remains qualified and will continue to meet the requirements of 10 CFR 50.49.

2.3.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The NRC staff's review covers the information, analyses and documents for the offsite power system and the stability studies for the electrical transmission grid. The focus of the review relates to the basic requirement that the loss of the nuclear unit, the largest operating unit on the grid, or the loss of the most critical transmission line will not result in the loss of offsite power to the plant. Branch Technical Position (BTP) Instrumentation and Control System Branch (ICSB)-11, "Stability of Offsite Power Systems," outlines an acceptable approach to addressing the issue of stability of offsite power systems. Acceptance criteria are based on GDC 17 of Appendix A to 10 CFR Part 50. Specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to Section 8.2 and BTPs Power System Branch (PSB)-1 and ICSB-11.

Technical Evaluation

2.3.2.1 Grid Stability

The study to evaluate the impact of EPU operation on the grid stability was performed by General Electric's Power Systems Energy Consulting (PSEC) group in cooperation with transmission system operator, American Transmission Systems Incorporated (ATSI). The dynamic system performance (i.e., first swing stability and system damping characteristics) in response to various events was evaluated based upon updated system modeling, under 2003 peak (summer) load and 2004 light (winter) load conditions.

For EPU, if one of the BVPS units trip, the transmission system around BVPS and the remaining BVPS unit have sufficient reactive capability to support the 345 kV system. For loss of BVPS-1, BVPS-2 must supply 332 MVAR, which is well within its capability. Similarly, for the

loss of BVPS-2, BVPS-1 must supply 308 MVAR which is well within its capability. If the grid voltage drops below 343 kV, the transmission system operator will begin to take action to bring the grid voltage up to 345 kV. BVPS EPU calculations determined that both BVPS-1 and BVPS-2 can supply up to a maximum of 375 MVAR. This is greater than the 349 MVAR for BVPS-1 and 353 MVAR for BVPS-2 modeled in the stability studies and, therefore, no compensatory measures are necessary. The load flow calculations for EPU conditions indicate that the post-trip loads will have adequate voltage for a minimum voltage level of 341 kV. Therefore, the BVPS units do not require any support from the transmission system operator.

While the August 14, 2003, loss-of-offsite power (LOOP) event was not considered a Category D event but was rather a chain of events leading to a wide area outage, it is worth noting that BVPS was not significantly impacted by this event. The GE PSEC staff considered a number of extreme contingencies (NERC D) events. The study results indicated that the system is stable for all single-phase faults studied for BVPS power uprate cases under 2003 peak load and 2004 light load conditions. The following models were used to represent the generating unit at BVPS:

- Generating Units Model: GENROU - Solid rotor generator represented by equal mutual inductance rotor modeling.

- Excitation Systems Model: EXAC1 - IEEE type AC1 excitation system

- Dynamic Models include the BVPS EPU dynamic models and data for the generator, and exciter.

BVPS is part of the Pennsylvania, New Jersey, and Maryland (PJM) electrical system control area and as such, PJM assumes primary responsibility for performing on-line contingency analysis. However, FENOC's System Control Center also performs on-line contingency analysis. PJM provides on-line contingency analysis in accordance with their established nuclear plant communications protocol. PJM operating procedures provide instructions for transmission operators to inform the generating station of potential or actual voltage outside the established limit, contingency element and all corrective measures. PJM will initiate notification to nuclear plants if the PJM energy management system (EMS) results indicate nuclear substation voltage outside the established limit and the PJM operator believes he is unable to return system voltages above established limits.

The uprate study included fault scenarios to determine the extent of the instability and possible mitigation techniques. The study showed that there would be sufficient capacity remaining to support the BVPS auxiliary loads following these scenarios that resulted in instability. These faults do not result in the simultaneous failure of both circuits from the single event since the 138 kV power sources have sufficient capacity for the transfer to be successful upon unit trip. Therefore, PJM will be able to provide the minimum voltage required for BVPS operation in the event of a unit trip or both units trip under EPU conditions. This would minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, loss of power from the onsite electric power supplies. Therefore, the plants continue to be in conformance with GDC 17 for the EPU conditions.

2.3.2.2 Main Turbine Generator and Isolated Phase Bus Duct

The current nameplate rating of the main unit generator of each unit is 1,026 MVA, 923 MW, 448 MVAR (375 MVAR + BVPS only load 73 MVAR) based on 75 psig hydrogen, 22 kV, 0.90 power factor, 60 Hz, 1800 RPM. Upgrade of each main generator output to 1,070 MVA, 984.4 MW, 413 MVAR, 0.92 PF will occur as a part of the EPU project. The evaluation of each main generator was based on a comparison between the applicable generator parameters (i.e., generator reactive capability curve) and the minimum (i.e., 99.1 percent of rated voltage for BVPS-1, 99.9 percent of rated voltage for BVPS-2) and maximum (i.e., 101.4 percent for BVPS-1, 102.6 percent for BVPS-2) operating voltage constraints when each machine operates at EPU conditions. The generator operation at leading power factor is restricted due to the existing generator stator design. At EPU conditions, the real power output of the BVPS-1 and 2 main generators will be 984 MWe and 977 MWe, respectively. Station load flow analyses confirm the machines are adequate at EPU conditions.

The existing Iso-phase bus (IPB) ducts main bus forced air-cooled rating is 28000 Amps, continuous. Station load flow analyses confirm that the main bus ratings are adequate at EPU conditions for both units. The taps from the IPB main bus to the unit station service transformers (USSTs) of each unit have a self-cooled rating of 3000 Amps. The station load flow analysis at EPU conditions for each unit confirms that the tap buses are adequate.
The NRC staff reviewed the licensee's submittal and determined that the main generator and IPB are adequately sized to support unit operation at EPU conditions.

2.3.2.3 Main Power Transformer (MPT)

The BVPS-1 and 2 MPTs are oil filled units. The BVPS-1 MPT has a single primary winding. Its nameplate rating is 945/1,058.4 MVA FOA at 55 EC/65 EC rise, 21.5 kV primary, 345 kV secondary, three-phase, 60 HZ. The BVPS-2 MPT is similarly rated but was furnished with a dual primary winding. The existing BVPS-2 MPT air coolers were replaced resulting in a new maximum transformer load capability of 1020 MVA. Station electrical load flow analyses prepared for each unit concluded that each MPT is adequately sized to support unit operation at EPU conditions when the main generator is operated within its rated capability curve at a lagging power factor and the unit auxiliary power system is supplied from the associated USST. This is the normal mode of operation for the MPTs.

2.3.2.4 Unit Station Service Transformer

The APS for each unit is normally supplied power through two USSTs. The nameplate rating for each USST is 19.2/25.6/32 MVA OA/FOA/FOA at 55 EC rise and 21.5/28.7/35.8 MVA OA/FOA/FOA at 65 EC rise, 22 kV primary, dual 4.36/4.36 kV secondary windings (X and Y), three-phase, 60 HZ. Each secondary winding is rated 9.6/12.8/16 MVA OA/FOA/FOA at 55 EC rise and 10.8/14.3/17.9 MVA OA/FOA/FOA at 65 EC rise. The USSTs are adequately sized to support operation of each unit at EPU conditions. Load flow analyses for each unit show that the total load supplied by each USST does not exceed the overall 65 EC rating of the transformer. The system model used to determine USST loading is a bounding case because it models Bus 1A supplying power to two additional 480 V buses due to a cross-tie between the buses of two downstream double-ended 480 V load centers. The USST oil and winding temperatures (for X and Y windings) are monitored per existing operating procedures. Based on station operating data and the total calculated transformer loading, the USSTs are adequately sized to support unit operation at EPU conditions.

2.3.2.5 System Station Service Transformer (SSST)

The nameplate rating for each SSST is 19.2/25.6/32 MVA OA/FOA/FOA at 55 EC rise and 21.5/28.7/35.8 MVA OA/FOA/FOA at 65 EC rise, 138 kV primary, dual 4.36/4.36 kV secondary windings (X and Y), three-phase, 60 HZ. Each secondary winding is rated 9.6/12.8/16 MVA OA/FOA/FOA at 55 EC rise and 10.8/14.3/17.9 MVA OA/FOA/FOA at 65 EC rise. Each SSST secondary winding is equipped with an automatic load tap changer that regulates the voltage to a preset value at the 4160 VAC normal buses fed from the transformer secondaries. Each SSST is capable of assuming load from the safety-related and non-safety related buses upon loss of power from the normal (USST) source via an automatic transfer scheme. The SSSTs are adequately sized to support the operation of BVPS-1 and 2 at EPU conditions. The load flow analyses for each unit show that the total load supplied by each SSST does not exceed the overall 65 EC rating of the transformer. The system model used to determine SSST loading is a bounding case because it models Bus 1A supplying power to two additional 480 V buses due to a cross-tie between the buses of two downstream double-ended 480 V load centers. The SSST oil and winding temperatures (for X and Y windings) are monitored per the existing operating procedures. Based on station operating data and the total calculated transformer loading, the SSSTs are adequately sized to support unit operation at EPU conditions.

2.3.2.6 Switchyard

The evaluation for the 345 kV and 138 kV switchyards concluded that the equipment and components associated with the 345 kV and 138 kV overhead lines between the station and the switchyards are adequate under EPU conditions. The evaluation also concluded that the equipment in the 345 kV and 138 kV switchyards are adequate under EPU conditions. The licensee's evaluation was performed in accordance with the "Beaver Valley Substation Component Capability Review," April 3, 2002. The NRC staff reviewed the licensee's evaluation and concurs in its findings.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's submittal for the effect of the proposed power uprate on the offsite power system and concludes that the offsite power system will continue to meet the requirements of GDC 17 following implementation of the proposed modifications for the power uprate. The staff further concludes that the impact of the proposed power uprate on grid stability is insignificant.

2.3.3 Emergency Diesel Generators

<u>Regulatory Evaluation</u>

The AC onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to the safety-related equipment. The NRC staff's review covers the descriptive information, analyses, and referenced documents for the AC onsite power system. Acceptance criteria are based on GDC 17 as it relates to the capability of the AC onsite power system to perform its intended functions during all plant operating and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.1.

Technical Evaluation

Four emergency diesel generators (EDGs), two per unit, provide onsite power to associated safety-related 4160 V buses in the event of a design-basis accident coincident with a loss of offsite power and other loss of normal power events. In the event of a station blackout (SBO), the EDG system of the unaffected unit serves as an alternate power source for safe shutdown of the affected unit. EDG steady state loading calculations have been revised to incorporate load increases experienced by the 4160 V charging pump motors and the 460 V CRDM shroud fan motors of each unit. The revised analyses confirm that the existing EDGs are adequately sized to support unit operation at EPU conditions. EDG loading is not affected by the load increase experienced by the 460 V containment air recirculation fan motors of either unit. Although the motors are supplied from 480 V emergency load center buses downstream of the 4160 V emergency buses, they are not required to be automatically loaded on the EDGs for any of the postulated loading scenarios.

Conclusion

There are negligible load changes to the safety-related buses and EDGs due to the EPU. The onsite power system will continue to meet the requirements of GDC 17. The engineered safeguard loads have not changed. The capacity of each EDG is adequate to support the operation of required engineered safeguards under design-basis accident conditions. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the onsite AC power system.

2.3.4 DC Distribution System

Regulatory Evaluation

The DC power systems include those DC power sources and their distribution systems and auxiliary supporting systems provided to supply motive or control power to safety-related equipment. The NRC staff's review covers the information, analyses, and referenced documents for the DC onsite power system. Acceptance criteria are based on GDC 17 and 10 CFR 50.63 as they relate to the capability of the DC onsite electrical power to facilitate the functioning of structures, systems, and components important to safety. Specific review criteria are contained in SRP Sections 8.1 and 8.3.2.

Technical Evaluation

The 125 VDC system was evaluated for loading changes due to EPU conditions for both units. For BVPS-2, there are no plant changes that would impact the design loading capability of the 125 VDC system, and therefore the 125 VDC system is adequate for EPU conditions. For BVPS-1, the only change to the 125 VDC system was the addition of the fast closing feedwater isolation valve circuitry. The revised analysis shows that there is no impact to the design loading capability of the 125 VDC system. Therefore, the 125 VDC system is adequate for EPU conditions.

Conclusion

The 125 VDC distribution system will continue to function as designed. Adequate separation exists, and the system has the capability to continue to supply adequate power to both safety-related and non-safety-related equipment. The system will continue to meet the requirements of GDC 17 following implementation of the EPU.

2.3.5 Station Blackout (SBO)

Regulatory Evaluation

SBO refers to the complete loss of AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the loss of offsite power concurrent with 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" (AAC). The NRC staff's review focused on the impact of the proposed power uprate on the plant's ability to cope with and recover from an SBO event pursuant to the SBO rule, 10 CFR 50.63. Specific review criteria are contained in SRP Section 8.1 and Appendix B to SRP Section 8.2.

Technical Evaluation

The NRC requires that each nuclear power plant be able to cope for a specified period and recover from an SBO event per the SBO rule. SBO is defined as the complete loss of AC power to the essential and non-essential switchgear busses. BVPS has been evaluated against the requirements of the SBO rule using NUMARC 87-00 and RG 1.155. Per this evaluation, an AAC source is available within 1 hour of the onset of SBO. BVPS-1 utilizes onsite emergency AC (EAC) power from BVPS-2 as an AAC power source using the permanently installed 4 kV SBO cross-tie with manual operator action. Similarly, BVPS-2 utilizes onsite EAC power from BVPS-1 as an AAC power source using the permanently installed 4 kV SBO cross-tie with manual operator action. During an SBO, station batteries, inverters and related 125 VDC distribution systems are available with capability to cope during the initial 1-hour period prior to AAC capability. For BVPS-2, there are no plant changes that would impact the design loading capability of the 125 VDC system, and therefore, the 125 VDC system is adequate for EPU conditions. For BVPS-1, the only change to the 125 VDC system was the addition of the fast closing feedwater isolation valve circuitry. The revised analysis shows that there is no impact to the design loading capability of the 125 VDC system. Therefore, the 125 VDC system is adequate for EPU conditions. The assumptions, systems and equipment credited for SBO coping were reviewed for an impact resulting from EPU. EPU will result in higher reactor coolant system, main steam, and feedwater temperatures, as well as higher decay heat. The overall magnitude of these increases is small and equipment temperatures will remain below the profiles of the existing accident/room heat-up analyses. The condensate inventory for decay heat removal during a SBO remains adequate (122,000 gallons) at the higher EPU power level. The minimum permissible condensate storage tank level per technical specification provides 140,000 gallons of water for BVPS-1 and 127,000 gallons for BVPS-2. The SBO coping capability at the current licensed power level was found to support EPU and no system modifications are required.

Conclusion

The NRC staff has evaluated the effect of power uprate on the necessary electrical systems and EQ of electrical components. Results of these evaluations show that operation of the BVPS-1 main generator and the BVPS-2 main transformers will be acceptable for EPU conditions following implementation of the proposed modifications to support the EPU. The EPU would have negligible impact on the grid stability, SBO, or the EQ of electrical components. After the modifications to support EPU, the design will continue to meet the requirements of GDC 17, 10 CFR 50.63, and 10 CFR 50.49 and the proposed changes will, therefore, be acceptable.

2.4 Instrumentation and Controls

Regulatory Evaluation

Instrumentation and control systems are provided (1) to control plant processes having a significant impact on plant safety, (2) to initiate the reactivity control system (including control rods), (3) to initiate the engineered safety features (ESF) systems and essential auxiliary supporting systems, and (4) for use to achieve and maintain a safe shutdown condition of the plant. Diverse instrumentation and control systems and equipment are provided for the express purpose of protecting against potential common-mode failures of instrumentation and control protection systems. The NRC staff conducted a review of the reactor trip system, engineered safety feature actuation system (ESFAS), safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed EPU to ensure that the systems and any changes necessary for the proposed EPU are adequately designed such that the systems continue to meet their safety functions. The NRC staff's review was also conducted to ensure that failures of the systems do not affect safety functions. The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and GDCs 1, 4, 13, 19, 20, 21, 22, 23, 24, 25, and 29. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.5, and 7.7.

Technical Evaluation

2.4.1 Suitability of Existing Instruments

For the proposed power uprate, the licensee evaluated each instrument of the affected NSSS and BOP systems in both BVPS units to determine its suitability for the revised operating range of the affected process parameters. Where operation at the power uprate condition impacted safety analysis limits, the licensee verified that the acceptable safety margin continued to exist under all EPU conditions. Where necessary, the licensee revised the instrumentation setpoint AV in the plant TSs for the affected instruments. The licensee's evaluations established revisions of the setpoint AVs for the following functional units in BVPS-1 and 2 reactor trip system (RTS) and ESFAS TSs that were impacted by the EPU. Additionally, some administrative changes are also incorporated in the proposed changes to the TSs.

(a) RTS Instrumentation (TSs Tables 3.3-1 and 4.3-1 for both BVPS-1 and 2)

Functional Unit 4, "Power Range, Neutron Flux High Negative Rate" trip has been deleted. This change was previously approved by the NRC staff in the SE related to

WCAP-11394 dated, October 23, 1989. Additionally, this trip function is not credited in the EPU analysis documented in the EPULR. Therefore, the proposed TS change is acceptable.

(b) RTS Instrumentation (TS Table 3.3-1 in BVPS-1)

(1) Changes in Overtemperature ΔT (OTΔT) and Overpower ΔT (OPΔT) Equation

The existing BVPS-1 safety analysis did not require the use of a lead/lag compensator function. Therefore, the OTΔT and OPΔT equations do not include functions generated by the lag compensator for measured ΔT and measured T_{avg} as are included in the Westinghouse Standard Technical Specifications (NUREG-1431). The lag compensators were subsequently added to increase operating margin by reducing signal noise impact to the trip functions. This addition will modify the existing OTΔT and OPΔT equations such that lag compensation is consistent with the mathematical form in NUREG-1431.

The proposed change to the TSs functional unit 7 and 8 (Notation A and B) is to add functions generated by the lag compensator for measured ΔT and measured T_{avg} in the OTΔT and OPΔT equations. These functions will include time constants τ_4 and τ_5 whose values are specified in the plant COLR. These changes will optimize operating margin at the EPU conditions. The current TSs Bases states that the OPΔT trip is not credited. This statement will be deleted because the OPΔT trip is credited in the EPU analyses. The staff finds the proposed changes acceptable because they will achieve consistency with the Standard Technical Specifications.

(2) Steam Generator Water Level Low-Low

Steam generator water level low-low signal reactor trip and auxiliary feedwater initiation function instrumentation setpoint allowable value was revised from $19.6 percent to $ 19.1 percent. This change was accepted in Amendment No. 273, previously issued to FENOC. Therefore, the NRC staff finds the proposed change acceptable.

(3) Permissive Change

The permissive specified in Action 8 of the LCO will be changed from P-7 to P-9. This change from P-7 to P-9 was accepted by the NRC staff in its review of LAR 35 with the issuance of Amendment No. 62 in 1983, but the change was not incorporated in Action 8 of this table, as it was not requested in LAR 35. This change is not related to the EPU and is being made to correct an existing inconsistency in the BVPS-1 TSs and for providing consistency with BVPS-2 TSs. Operation using permissive P-7 in Action 8 of this Table since Amendment No. 62 was issued in 1983 has been unnecessarily conservative. The proposed change is administrative and therefore, is acceptable.

(c) ESFAS Instrumentation (TS Table 3.3-3 in BVPS-1)

(1) Steam Generator Water Level High-High Setpoint AV

The SG water level high-high turbine trip and feedwater isolation initiation function instrumentation setpoint AV was increased from #81.7 percent to #90.2 percent in Amendment No. 273 previously issued to the licensee. FENOC stated that the proposed AVs are based on the analyses for EPU provided in Westinghouse Topical Reports WCAP-11419, Revision 4 and WCAP-11366, Revision 6, and Westinghouse recommendations in Nuclear Safety Advisory Letter NSAL-03-09. These reports were found acceptable in Amendment No. 239, previously issued to FENOC. Since this LSSS value is based on the NRC staff-approved performance-based setpoint methodology, the staff finds the proposed change acceptable.

(2) Footnote Addition

A footnote is added to steam line pressure low setpoint AV used for steam line isolation and provides information regarding the time constants utilized in the lead-lag controllers for steam line pressure-low. This change is not related to EPU and is included to provide consistency with BVPS-2 TSs. The change is considered administrative, and therefore, acceptable.

(d) NSSS Control System Instrumentation

FENOC evaluated both units' NSSS control system performance and setpoints at EPU conditions. This evaluation resulted in changes to the reactor coolant average temperature program, the steam dump control system setpoints, and the pressurizer level control program for both units, and the SG level control setpoint change for BVPS-1. FENOC's evaluation established that with these changes, the NSSS control systems remain stable under the EPU conditions for both BVPS-1 and 2. These changes will be made to accommodate the revised process parameters. Since these changes are based on and are consistent with the system analyses reviewed and approved by the NRC staff elsewhere in this SE, they are acceptable.

(e) Feedwater Flow Instrumentation Operability

The feedwater flow measurement used in calculation of the daily calorimetric heat balance is provided by an ultrasonic flow meter called the leading edge flow meter (LEFM) at both units. Operability of this instrument is controlled by the Licensing Requirements Manual, Item LR 3.8. The applicability statement in BVPS-2 LR 3.8 includes an asterisk footnote defining the applicable steady-state thermal power. This footnote was not corrected for operation at EPU conditions and showed the current plant operating conditions. This footnote will be changed based on the power ascension testing to properly reflect a power reduction of 1.4 percent RTP from the EPU conditions for an inoperable LEFM. This change to the Licensing Requirements Manual accurately incorporates the post-EPU RTP into the requirements, therefore, the NRC staff finds this change to be acceptable.

These changes will be made to accommodate the revised process parameters. Since these changes are based on the system analyses reviewed by the NRC staff and the licensee will confirm the acceptability of these changes during power ascension testing, the staff agrees with

the licensee's conclusion that when the above changes are implemented, BVPS-1 and 2 instrumentation and control systems will accommodate the proposed power uprate without compromising safety. None of the above changes affect compliance with the existing plant licensing basis and therefore, BVPS-1 and 2 continue to meet the current regulatory requirements.

2.4.2 Instrument Setpoint Methodology

All of the proposed changes in TSs for the EPU amendment request regarding instrument setpoint allowable values have been approved in Amendment Nos. 270, 271 and 273 and Amendment Nos. 152 and 153 for BVPS-1 and 2 which were issued and are discussed in the various sections of the SEs for those Amendments. Therefore, the NRC staff did not review the instrument setpoint methodology for BVPS-1 and 2 in this SE. The staff review of the instrument setpoint methodology is documented in the SE dated January 11, 2006, supporting Amendment Nos. 270 and 152 for BVPS-1 and 2, respectively [78].

Conclusion

The NRC staff has reviewed the licensee's application related to the effects of the proposed EPU on the functional design of the RTS, ESFAS, safe-shutdown system, and control systems. The staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these systems and that the changes that are necessary to achieve the proposed EPU are consistent with the plant's design basis. The staff further concludes that the systems will continue to meet the requirements of 10 CFR 50.55a(a)(1), 10 CFR 50.55(a)(h), and GDCs 1, 4, 13, 19, 20, 21, 22, 23, 24, 25, and 29. Therefore, the staff finds the licensee's proposed EPU acceptable with respect to instrumentation and controls aspects of the proposed EPU for BVPS-1 and 2.

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

For proposed power uprates, the NRC staff reviews flood protection measures to ensure that SSCs important to safety are adequately protected from the consequences of internal flooding that result from postulated failures of tanks and vessels. Because the staff's review focuses on increases of fluid volumes in tanks and vessels that will occur as a result of a proposed power uprate and the EPU does not result in a significant increase in the volume of fluids held by systems or storage tanks at BVPS-1 or 2 in any area where safety-related equipment would be affected, an evaluation of this particular area by the staff is not required.

2.5.1.1.2 Equipment and Floor Drains

The function of the equipment and floor drainage system (EFDS) is to assure that waste liquids, valve and pump leakoffs, and tank drains are directed to the proper areas for processing or disposal while preventing a backflow of water that might result from maximum flood levels to

areas of the plant containing safety-related equipment. Because the sources and quantities of liquids that enter the equipment and floor drains will remain unchanged for the proposed power uprate at BVPS-1 and 2, an evaluation of the EFDS is not required.

2.5.1.1.3 Circulating Water System

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove excess heat from the turbine cycle and auxiliary systems. For proposed power uprates, the NRC staff's review of the CWS focuses on the impact that the proposed uprate will have on existing flooding analyses due to any increases that may be necessary in fluid volumes and installation of larger capacity CWS pumps or piping. Because the impact of the proposed power uprate on the licensee's flooding analysis is considered in Sections 2.5.1.1.1 and 2.5.1.3 of this evaluation, a separate evaluation for the CWS in this section is not required.

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

The NRC staff's review concerns missiles that could result from in-plant component overspeed conditions and ruptures of high pressure systems. The purpose of the staff's review is to confirm that SSCs important for event mitigation and plant shutdown are adequately protected from internally generated missiles and that failure of other SSCs will not pose a challenge to those SSCs that are relied upon. The staff's review focuses on system modifications, increases in system pressures, and changes in component overspeed conditions that may be necessary following implementation of the proposed power uprate and are not bounded by existing analyses. Because the licensee found that: (1) there are no new components or changes to existing systems and components associated with the EPU that create the potential for new internally generated missiles, and (2) the EPU will not result in a significant increase in system pressures or in rotational energy for existing equipment and components that could result in the potential for additional or more severe internally generated missiles, an evaluation to confirm the adequacy of protective features for internally generated missiles is not required.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The large steam turbines of the main turbine generator (TG) sets have the potential for producing large high-energy missiles, especially if the turbines should exceed their rated speed. Consequently, turbine overspeed protection is provided to assure that design limits will not be exceeded. The licensee will be replacing the high pressure (HP) turbine at BVPS-2 prior to operation at EPU power levels, and has already replaced the BVPS-1 HP turbine with an all reaction turbine. The NRC staff's review of the TG sets focuses on the effects of the proposed EPU on the turbine overspeed protection features to confirm that adequate turbine overspeed protection will be maintained. The acceptance criteria that are most applicable to the staff's review of the TG for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC 4, "Environmental and Dynamic Effects Design Bases," insofar that SSCs important to safety

should be protected from the effects of turbine missiles by providing a turbine overspeed protection system; and other licensing-basis considerations that are applicable. The staff's review of the TG is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability of the TG for EPU operation is judged based upon conformance with existing licensing basis considerations as discussed primarily in Section 10.3.3 of the UFSAR for BVPS-1 and Section 10.2 of the UFSAR for BVPS-2, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the TG overspeed protective function is provided in Section 8.1 of the BVPS-1 and 2 EPULR. Each TG set has a turbine control and overspeed protection system. Overspeed protection is accomplished by three independent systems: (1) a normal speed governor, (2) a mechanical overspeed trip, and (3) an electrical backup overspeed trip. The normal speed governor overspeed protection is activated in the event the turbine speed exceeds 103 percent of rated speed. Should the turbine speed exceed approximately 111 percent of rated speed, the turbine is tripped by both the mechanical and the backup electrical overspeed trip systems. In a letter dated July 28, 2005, the licensee provided additional information in response to a question that was asked by the NRC staff concerning turbine overspeed protection capabilities. In its response, the licensee confirmed that the existing turbine missile generation analyses, which utilize probabilistic methodology, remains bounding for both units post-EPU. The licensee also indicated that an evaluation was performed for BVPS-1 to determine the expected overshoot of the turbine upon a loss of load, and a maximum overspeed of 118 percent was calculated for the worst case overspeed condition at uprated power, which remains less than the 120 percent turbine design value. As for BVPS-2, the licensee expects that the 120 percent turbine overspeed trip design limit will remain bounding, and indicated that a turbine overspeed analysis will be completed when the BVPS-2 HP turbine replacement is installed as part of the design change management process.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on TG overspeed protection, including turbine overshoot considerations. The licensee's determination that overspeed protective features will prevent the BVPS-1 turbine from exceeding the design rating provides adequate assurance that BVPS-1 SSCs will be protected from turbine overspeed conditions during EPU operation. The licensee provided a commitment (Commitment No. 1 of Enclosure 3) in its November 8, 2005, RAI response to complete this analysis for BVPS-2 as part of the design change management process before placing the modified BVPS-2 turbine in service. The staff considers that a commitment by the licensee to complete the turbine overspeed analysis and to confirm acceptable performance for BVPS-2 prior to EPU operation (following installation of the HP replacement turbine) is acceptable and will assure that the BVPS-2 SSCs are adequately protected from turbine overspeed conditions during EPU operations. The licensee has not requested NRC review and approval of any changes to the licensing basis for TG overspeed protection relative to EPU operation and this evaluation does not constitute NRC approval of any changes to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of changes being made to the HP turbine, steam mass flow rate, and other operational characteristics necessary to support the proposed EPU. In consideration of the licensee's evaluation related to the BVPS-1 turbine and the licensee's regulatory commitment to complete the turbine overspeed analysis and confirm acceptable performance prior to commencing EPU operation on BVPS-2, the staff finds that existing design features will continue to protect the main turbine from overspeed conditions following postulated transient and accident conditions in accordance with licensing-basis assumptions. Therefore, the proposed EPU is considered to be acceptable with respect to TG overspeed protection considerations.

2.5.1.3 Pipe Failures

Regulatory Evaluation

The failure of high and moderate energy piping can cause pipe whip, jet impingement, and harsh environmental conditions that can result in extensive damage and render SSCs inoperable. The NRC staff's review for EPUs is concerned with the impact that the proposed power uprate will have on the capability that is credited for mitigating the failure of high and moderate energy fluid piping that is located outside containment and for safely shutting down the plant in accordance with the plant licensing basis. The staff's review focuses on those system modifications and increases in system pressures and temperatures that are necessary in order to implement the EPU in order to confirm that the limitations and assumptions of previous pipe failure analyses remain valid or are otherwise addressed. The acceptance criteria that are most applicable to the staff's review of postulated pipe failures for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC 4, insofar that SSCs important to safety should be designed to accommodate the dynamic effects of postulated pipe ruptures, including the effects of pipe whip and discharging fluids; and other licensing-basis considerations that are applicable. The staff's review associated with postulated pipe failures is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Attachments A & B of Section 5.2, Table 6.4-3, and Appendix B of the UFSAR for BVPS-1 and Section 3.6B.1 of the UFSAR for BVPS-2, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the consequences of high energy line breaks (HELBs) and moderate energy pipe cracks (MEPCs) that are postulated to occur outside containment is discussed in Sections 8.4, 8.5, and 10.10 of the BVPS-1 and 2 EPULR, as supplemented by letter dated July 28, 2005. The licensee has determined that the temperatures and pressures that were used in the existing pipe failure and effects analyses will not be exceeded as a consequence of EPU operation and therefore, the existing design basis for protection against the dynamic effects associated with postulated high and moderate energy pipe failures is not impacted. The mass and energy releases for postulated HELBs remain within analyzed conditions and therefore, the pressure and temperature response for rooms and subcompartments outside containment will not be impacted, there will be no increase in pipe whip or jet impingement forces, existing jet shields and pipe whip restraints will continue to be adequate for EPU operation. For those areas where MEPCs represent the most limiting failure, the licensee confirmed that EPU will not introduce any spray or jet impingement effects;

and no new pipe failure locations were identified as a result of the proposed power uprate. The licensee also evaluated the impact of the proposed power uprate on the extent of flooding that could occur due to postulated pipe failures and determined that the existing analyses continue to be valid.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the consequences of postulated high and moderate energy pipe failures, including flooding considerations. The licensee has not requested NRC review and approval of any changes to the licensing basis for postulated high and moderate energy pipe failures relative to EPU operation that are within the scope of this evaluation section. As discussed in Section 2.2.2 of this SE, the postulation of intermediate pipe break locations for BVPS-2 and the change to the criteria presented in UFSAR Sections 3.6B.2.1.1.2 and 3.6B.2.1.2.1 for ASME Code, Section III, Class 2 and 3 piping and seismic non-nuclear piping applies to the EPU analyses.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the consequences of postulated high and moderate energy pipe failures and finds that protection of essential SSCs from the effects of high and moderate energy pipe failures will continue to satisfy licensing-basis assumptions following EPU implementation. Therefore, the proposed EPU is considered to be acceptable with respect to high and moderate energy pipe failure considerations.

2.5.2 Pressurizer Relief Tank

Regulatory Evaluation

The pressurizer relief tank (PRT) is a pressure vessel provided to condense and cool the discharge from the pressurizer safety valves. The tank is designed with a capacity to absorb discharged fluid from the pressurizer relief valves during a specified step-load decrease. The PRT system is not safety related and is not designed to accept a continuous discharge from the pressurizer. The purpose of the NRC staff's review is to confirm that operation of the PRT will continue to be consistent with the transient analysis of the RCS following implementation of the proposed power uprate, and that failure or malfunction of the PRT will not adversely affect safety-related SSCs. The staff's review focuses on any modifications to the PRT and connected piping, and changes related to operational assumptions that are necessary in support of the proposed EPU. In general, the steam condensing capacity of the tank and the tank rupture disk relief capacity should be adequate, taking into consideration the capacity of the pressurizer power-operated relief and safety valves; the piping to the tank should be adequately sized; and systems inside containment should be adequately protected from the effects of high energy line breaks and moderate energy line cracks associated with the pressurizer relief system. The acceptance criteria that are most applicable to the staff's review of the PRT for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC 4, insofar that SSCs important to safety should be designed to accommodate and be compatible with specified environmental conditions and be protected against dynamic effects, including the effects of missiles; and other licensing-basis considerations that apply. The staff's review of the PRT is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability of the PRT for EPU operation is judged based upon conformance with existing

licensing basis considerations as discussed primarily in Section 4.2.2.3 of the UFSAR for BVPS-1 and Section 5.4.11 of the UFSAR for BVPS-2, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the capability of the PRT to continue to provide adequate relief capacity following a maximum expected pressurizer pressure discharge condition is provided in Sections 3.2.2 and 9.1 of the BVPS-1 and 2 EPULR. The PRT is sized to receive and condense a discharge of 110 percent of the full-power pressurizer steam volume. Since the original PRT design basis assumed that pressurizer water level was initially at 60 percent, resulting in a steam space volume of 40 percent (560 cubic feet), for PRT sizing purposes it was assumed that 110 percent of the steam space volume (616 cubic feet) would be discharged to the PRT. The steam volume requirement is approximately that which would be experienced if the plant were to suffer a complete loss of load accompanied by a turbine trip but without a resulting reactor trip. If a discharge exceeding this design-basis capacity should occur, overpressure protection for the tank is provided by a rupture disk that vents to the containment atmosphere with a relief capacity equal to or greater than the combined relief capacity of the pressurizer safety valves. The turbine trip event on which the PRT sizing is based credits only the pressurized safety valves for limiting pressure, no credit is taken for use of the PORVs or pressurizer spray.

The largest pressurizer steam space volume change is for the loss of normal feedwater (LONF) transient. The licensee has revised its non-LOCA safety analysis for the LONF transient to incorporate EPU operating conditions. The revised analysis assumes an initial pressurizer water level of 67 percent (nominal water level of 60 percent plus 7 percent uncertainty) and confirms that the pressurizer does not fill. Thus the steam volume discharged to the PRT is less than 33 percent (462 cubic feet). In addition, the PRT pressure will not exceed 50 psig following a design basis release of steam from the pressurizer. The peak pressure is well below the rupture disc set pressure of 85 psig for BVPS-1 and 86 psig for BVPS-2. Because the PRT is sized to accept a steam volume of 616 cubic feet from the pressurizer, and for the LONF transient at EPU conditions only 462 cubic feet of steam will be discharged to the PRT, the PRT will continue to have sufficient capacity to perform its design basis function for EPU conditions. Consequently, the PRT will continue to operate in a manner that is consistent with the transient analysis for the reactor coolant system and SSCs will continue to be protected against postulated failures of the PRT.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the PRT to condense and contain steam that is discharged from the pressurizer safety valves and to protect SSCs from postulated PRT failures. The licensee has not requested NRC review and approval of any changes to the PRT licensing basis relative to EPU operation and this evaluation does not constitute NRC approval of any changes to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the PRT to perform its safety function and finds that the PRT will remain

capable of condensing and containing steam that is discharged from the pressurizer safety valves, and safety-related SSCs will continue to be protected from PRT failures, following postulated transient and accident conditions in accordance with licensing-basis assumptions. Therefore, the proposed EPU is considered to be acceptable with respect to the PRT.

2.5.3 Fission Product Control

2.5.3.1 Fission Product Control Systems and Structures

The purpose of the NRC staff's review of fission product control systems and structures is to confirm that current analyses remain valid or have been revised, as appropriate, to properly reflect the proposed EPU conditions. Consequently, the staff's review focuses primarily on any adverse effects that the proposed EPU might have on the assumptions that were used in the analyses that were previously completed. Because the impact of EPU on plant systems and structures identified by the licensee as making up the fission product control system are addressed in this SE in Section 2.6, "Containment Review Considerations," Section 2.7, "Habitability, Filtration, and Ventilation," and Section 2.9, "Source Terms and Radiological Consequences Analyses," a separate review of this area is not required.

2.5.3.2 Main Condenser Evacuation System

The main condenser evacuation system (MCES) is not impacted by the proposed power uprate because the condenser air removal requirements during startup are not affected. The MCES is sized based on the volume of the condenser and desired evacuation time, neither of which is impacted by the proposed power uprate. Consequently, the existing capability to monitor the MCES effluent is also not affected by the proposed EPU and therefore, NRC review of the MCES is not required.

2.5.3.3 Turbine Gland Sealing System

The turbine gland sealing system (TGSS) is designed to provide sealing steam for the TG shaft and to prevent leakage of air into the turbine casing and the escape of steam into the turbine building, thereby preventing the uncontrolled release of radioactive material from steam in the turbine to the environment. Because no modifications are being made to the TGSS and non-condensable gases will continue to be monitored for radiation, the function of the TGSS will not be impacted by the proposed power uprate and an evaluation of the TGSS is not required.

2.5.4 Component Cooling and Decay Heat Removal

2.5.4.1 Spent Fuel Pool Cooling and Cleanup System

The spent fuel pool cooling and cleanup system (SFPCCS) provides cooling for the spent fuel assemblies and keeps them covered with water during all storage conditions. The NRC staff's review for proposed power uprates focuses on the capability of the SFPCCS to accommodate the additional heat load that will result from EPU operation in accordance with the SFPCCS licensing basis. The NRC staff's approval of License Amendment Nos. 247 and 126 dated January 29, 2002, for BVPS-1 and BVPS-2, respectively, included an evaluation of the SFPCCS to perform its functions at the EPU power level (including margin for measurement

uncertainty). Because this previous evaluation of the SFPCCS included consideration of the uprated power level, no further evaluation is necessary.

2.5.4.2 River/Service Water System

Regulatory Evaluation

The BVPS-1 River Water System (RWS) and the BVPS-2 Service Water System (SWS) perform both safety and non-safety functions by providing essential cooling water to various safety-related and non-safety-related SSCs during all modes of plant operation. These systems will be referred to generically as the SWS. The NRC staff's review of the SWS for EPU operation focuses on the additional heat load that results from the proposed power uprate. The acceptance criteria that are most applicable to the staff's review of the SWS for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC 44, "Cooling Water," insofar that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions should be provided; and other licensing-basis considerations that are applicable. The staff's review is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.9 of the UFSAR for BVPS-1 and Section 9.2.1 of the UFSAR for BVPS-2, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the capability of the SWS to continue to provide essential cooling water to the various plant components (safety-related and non-safety-related) is provided in Section 9.15 of the BVPS-1 and 2 EPULR. The licensee determined that although EPU will result in a slight increase in the amount of heat that is rejected to the SWS, system design limitations will not be exceeded. The major contributor to the increased heat load due to EPU operation is the reactor decay heat that exists immediately after the residual heat removal (RHR) system is placed in service. Procedures will continue to require the reactor coolant flow to be regulated through the RHR heat exchangers during normal plant cooldown to assure that the component cooling water (CCW) system and SWS temperature limits will not be exceeded. Also, existing programmatic controls that were established in response to GL 89-13 will remain intact and continue to assure that heat exchanger performance is consistent with design-basis assumptions. The licensee concluded that the increase in heat load due to EPU will have an insignificant effect on the SWS and that the SWS will continue to satisfy its safety functions without the need for modifications or changes in existing flow requirements.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the SWS to perform its safety functions. Because design limitations of SSCs will not be exceeded and licensing-basis considerations will continue to be satisfied, the staff agrees that the capabilities of the SWS will not be impacted by the proposed power uprate. Furthermore, existing GL 89-13 programmatic controls will continue to assure that heat exchanger performance is maintained consistent with licensing-basis considerations following implementation of the proposed power uprate. The licensee has not requested NRC review and approval of any changes to the SWS licensing basis relative to EPU operation and this

evaluation does not constitute NRC approval of any changes to the plant licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SWS, and finds that the SWS will remain capable of performing its licensing-basis function following EPU implementation. Therefore, the proposed EPU is considered to be acceptable with respect to the SWS.

2.5.4.3 Reactor Auxiliary Cooling Water Systems

Regulatory Evaluation

Reactor auxiliary cooling water systems circulates water to remove heat from plant components during plant operation, plant cooldown, and post accident conditions. The reactor auxiliary cooling water systems for BVPS-1 is the reactor component cooling (CCR) system and for BVPS-2 it is the primary component cooling (CCP) system. These systems will be referred to generically as the CCW system. The NRC staff's review for proposed power uprates focuses on the continued capability of the CCW system to adequately cool critical plant equipment in accordance with licensing-basis assumptions. The acceptance criteria that are most applicable to the staff's review of the CCW system for proposed power uprates are based on GDC 44, insofar that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions should be provided; and other licensing-basis considerations that are applicable. The staff's review of the CCW system is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.4 of the UFSAR for BVPS-1 and Section 9.2.2 of the UFSAR for BVPS-2, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the capability of the auxiliary cooling water system to provide essential cooling water to plant components during plant operation, plant cooldown, and post accident conditions is provided in Section 9.6 of the BVPS-1 and 2 EPULR. The licensee found that the largest CCW system heat load occurs during reactor cooldown when the RHR system is initially placed into operation. The maximum cooldown rate is achieved by placing 3 CCW heat exchangers and 3 CCW pumps into service. While operating in this mode, the reactor coolant flow through the RHR heat exchangers is regulated to assure that the CCW system temperatures are maintained within their design limits, while still allowing the reactor to cooldown as quickly as possible. Evaluations were performed for the licensing-basis cooldown cases, which included the normal cooldown case for both BVPS-1 and 2, a UFSAR Appendix 5A cooldown case, and a UFSAR Section 5.4.7 single train cooldown case for BVPS-2. The licensee concluded that no changes would be required in the SWS or CCW system flow rates for EPU operation, and that existing controls to regulate the reactor coolant flow rate through the RHR heat exchangers are sufficient to assure that CCW system design limitations will not be exceeded.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the CCW system to perform its safety functions. The licensee has not requested NRC review and approval of any changes to the CCW system licensing basis relative to EPU operation and this evaluation does not constitute NRC approval of any changes to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the CCW system and finds that the CCW system will remain capable of performing its licensing-basis safety functions following EPU implementation. Therefore, the proposed EPU is considered to be acceptable with respect to the CCW system.

2.5.4.4 Ultimate Heat Sink

The ultimate heat sink (UHS) provides the cooling medium for dissipating the heat removed from the reactor and its auxiliaries during normal operation, refueling, and accident conditions. The Ohio River serves as the UHS for the Beaver Valley units and because its cooling capacity far exceeds the shutdown cooling and accident heat loads for the Beaver Valley units, it is unaffected by the proposed power uprate. Therefore, an evaluation of the UHS is not required.

2.5.4.5 Auxiliary Feedwater (AFW) System

Regulatory Evaluation

In conjunction with a seismic Category I water source, the AFW system functions as an emergency system for supplying feedwater to the SGs and (in conjunction with the atmospheric dump valves) for providing an alternative means of achieving cold shutdown following a plant fire when the RHR system is completely (BVPS-1) or partially (BVPS-2) unavailable. The system consists of 2 motor-driven AFW pumps, each with a rated capacity of 350 gallons-per-minute (gpm) for BVPS-1 and 375 gpm for BVPS-2; 1 turbine-driven AFW pump, with a capacity of 700 gpm for BVPS-1 and 750 gpm for BVPS-2; the primary plant demineralized water storage tank (PPDWST), with a capacity of 140,000 gallons for BVPS-1 and 169,696 gallons for BVPS-2; and associated piping and valves. The NRC staff's review for EPUs focuses on the capability of the AFW system to provide sufficient emergency feedwater flow to accommodate the increased decay heat load for the uprated plant consistent with licensing-basis considerations. The staff also reviews the effects of the proposed EPU on the likelihood of creating fluid flow instabilities (e.g., water hammer) during AFW system operation. The acceptance criteria that are most applicable to the staff's review of the AFW system for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC 34, "Residual Heat Removal," insofar as an RHR system should be provided to transfer fission product decay heat and other residual heat from the reactor core; GDC 44, insofar as a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions should be provided; and other licensing-basis considerations that are applicable. The staff's review of the AFW system is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 10.3.5 of the

UFSAR for BVPS-1 and Section 10.4.9 of the UFSAR for BVPS-2, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the capability of the AFW system to continue to provide an adequate supply of emergency feedwater to the SGs in the event normal feedwater is lost is provided in Section 9.23 and Section 3.1.4 of the BVPS-1 and 2 EPULR, as supplemented by letter dated July 28, 2005. The licensee found that the LONF and feedwater line break events establish the most limiting scenarios with respect to AFW system performance. For BVPS-1, the licensee determined that a total combined AFW system flow rate of 489 gpm will be required for SG makeup for the LONF event following EPU implementation. The minimum required flow rate exceeds the 350 gpm capacity of a single motor-driven AFW pump, but it is well within the combined capacities of any 2 of the 3 AFW pumps that are assumed to be available when allowing for a single active failure of 1 AFW pump. In addition the licensee's evaluation of the feedwater line break event for BVPS-1 assumed an AFW flow of 250 gpm to the intact SGs prior to isolation of the faulted SG and 400 gpm following isolation, with an assumed time of 15 minutes for operator action to isolate the faulted SG (the assumed operator action time review is contained in Section 2.11 of this SE). If the break occurs while an AFW pump is in an AOT, cavitating flow venturis are credited for limiting the amount of AFW flow that is lost through the break such that the 2 operable AFW pumps are capable of providing the required system flow prior to isolation of the faulted SG. Since no single failures are assumed to occur while in the AOT, all of the flow from the 2 operable AFW pumps will be available after isolation of the break and, therefore, the available AFW pumps will be able to provide the flow required to the 2 intact SGs to mitigate the feedwater line break event. Since the AFW system will continue to be able to mitigate the feedwater line break event with 1 AFW pump inoperable, the 72-hour AOT for an inoperable pump remains acceptable for the uprated BVPS-1 plant. Consequently, BVPS-1 will credit the flow from 2 AFW pumps (instead of one as is currently the case) for assuring adequate SG makeup capability during EPU operation, and the Bases for AFW system TS 3.7.1.2 will be revised accordingly to properly reflect the capability that is required for TS operability considerations. The staff reviewed TS 3.7.1.2 and concluded that no changes to the LCO or to the existing SRs are needed beyond the clarification that is proposed to the TS Basis. Similarly, the licensee determined that a total combined AFW system flow rate of 400 gpm will be required for BVPS-2 following EPU implementation. This is well within the capacity of 2 AFW pumps and is consistent with the existing licensing basis for BVPS-2 such that no TS changes or clarifications are required for BVPS-2 in this regard.

The NRC staff notes that the licensee has determined that for EPU conditions, a minimum PPDWST inventory of 130,000 gallons for BVPS-1 and 2 will be sufficient for maintaining each of the units in hot standby for 9 hours following a loss of offsite power. This compares with a minimum PPDWST inventory of 140,000 gallons (contained) and 127,500 gallons (usable) that is currently required for BVPS-1 and 2, respectively, for operation at the current licensed power level. However, the licensee did not address the capability to maintain BVPS-1 and 2 in hot standby followed by cooldown to RHR system entry conditions as recognized in the TS Bases for BVPS-1 and consistent with the criteria provided in SRP Section 5.4.7. AFW system inventory considerations and changes to the plant licensing basis in this regard are reviewed in Section 2.8 of this SE.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the AFW system to perform its safety functions. The licensee's plans to revise the Bases of TS 3.7.1.2 for BVPS-1 to properly reflect the need to credit the capacity of 2 AFW pumps for EPU operation instead of the capacity from only one pump will assure proper implementation of the TS operability requirements. The capacity requirements for BVPS-2 during EPU operation will continue to be consistent with the current plant licensing basis because 2 AFW pumps are already credited for plant operation at the current licenced power level. The licensee has not requested NRC review and approval of any changes to the licensing basis related to the AFW system for EPU operation with the exception of crediting 2 AFW pumps in the evaluation of the feedwater line break event. Based on the above, the staff finds this change acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed EPU will have on the AFW system and finds that the AFW system will continue to be capable of performing its safety functions in accordance with licensing-basis considerations. Therefore, the proposed EPU is considered to be acceptable with respect to the AFW system.

2.5.5 Balance-of-Plant (BOP) Systems

2.5.5.1 Main Steam

The main steam supply system (MSSS) transports steam from the NSSS to the power conversion system and various auxiliary steam loads. The NRC staff's review of the MSSS for proposed power uprates evaluates system design limitations to assure that reactor safety will be preserved. Much of the NRC staff's review of the MSSS for proposed power uprates involves other areas of review that are evaluated in other sections of this SE. The effects of increased steam flow and changes in steam quality on erosion/corrosion are evaluated in Section 2.1; the capability of the MSSS to withstand the steam hammer loads that result from the rapid closure of the main steam isolation valves (MSIVs), the capability of the MSIVs to isolate steam flow within the time period required, design considerations associated with the rapid closure of the MSIVs, protection of the SGs from overpressure conditions, and evaluation of piping stresses due to LOCA and SG nozzle loads are addressed in Section 2.2; and the capability of the MSSS to dissipate reactor decay heat in accordance with safe shutdown and accident analysis assumptions, positive reactivity considerations, and the transient effects of the MSSS on reactor performance and the need for transient testing in this regard are addressed in Sections 2.8 and 2.12; and protection of SSCs important to safety from the effects of HELBs and missiles is evaluated in Section 2.5.1. This section of the SE focuses primarily on any changes in the design or operation of the MSSS that could impact the capability of steam-driven equipment to function in accordance with safe shutdown and accident analysis assumptions or could otherwise result in increased challenges to reactor safety systems. Because no changes of this nature are being made, evaluation of the MSSS is not required.

2.5.5.2 Main Condenser

The main condenser is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system (TBS). For pressurized-water

reactors, the NRC staff's review of the main condenser for proposed power uprates focuses primarily on the impact that EPU will have on the extent and consequences of flooding that will occur as a result of a postulated failure of the main condenser. Because flooding considerations are evaluated in Section 2.5.1.1.1 of this SE, which includes consideration of flooding due to failure of the main condenser, a separate evaluation of the main condenser in this section is not required.

2.5.5.3 Turbine Bypass

The TBS is a non-safety-related system designed to discharge a stated percentage of rated main steam flow directly to the main condenser, bypassing the turbine and enabling the plant to take step load reductions up to the capacity of the TBS without causing the reactor or turbine to trip. The required capacity of the TBS for dissipating reactor decay heat in accordance with safe shutdown and accident analysis assumptions, positive reactivity considerations due to inadvertent TBS operation, and the transient effects of TBS operation on reactor performance and the need for transient testing in this regard are considered in Sections 2.8 and 2.12 of this SE, and the consequences of component missile and pipe failures are evaluated in Sections 2.5.1.2 and 2.5.1.3 of this SE, and consequently, these areas are not reviewed in this section. This section of the SE focuses primarily on any changes in the design and operation of the TBS that could compromise its capability to perform its assigned functions thereby increasing the potential for increased challenges to reactor safety systems. Because changes are not being made in the design and operation of the TBS, an evaluation of the TBS is not required.

2.5.5.4 Condensate and Feedwater

Regulatory Evaluation

The condensate and feedwater system (CFS) provides feedwater at the appropriate temperature, pressure, and flow rate to the SGs. The only part of the CFS that is classified as safety-related is the feedwater piping from the SGs up to and including the outermost containment isolation valves. The NRC staff's review of the CFS for proposed power uprates focuses primarily on system design limitations and reductions in operational flexibility that could result in unacceptable fluid flow instabilities or increased challenges to reactor safety systems. The effects of increased CFS flow on erosion/corrosion rates are evaluated in Section 2.1 of this SE; the capability of the main feedwater isolation valves (MFIVs) to isolate feedwater flow within the time period required, and the capability of CFS piping and supports to withstand postulated transient loads (such as those that result due to check valve slam) are evaluated in Section 2.2 of this SE; positive reactivity considerations and the transient effects of the CFS on reactor performance and the need for transient testing in this regard are addressed in Sections 2.8 and 2.12 of this SE; and, the consequences of component missiles and pipe breaks are evaluated in Sections 2.5.1.2 and 2.5.1.3 of this SE, and consequently, these areas are not reviewed in this section. The acceptance criteria that are most applicable to the staff's review of the CFS for proposed power uprates are based on existing plant licensing-basis considerations, especially with respect to maintaining CFS reliability and minimizing challenges to reactor safety systems during EPU operation. The staff's review of the CFS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 10.3.5 of the UFSAR for BVPS-1 and Section 10.4.7 of the UFSAR for

BVPS-2, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the CFS's ability to provide feedwater to the SGs is provided in Section 9.12 of the BVPS-1 and 2 EPULR. During EPU operation, feedwater and condensate flow will increase and the increased flow will result in an increase in the system pressure drop. The licensee determined that the CFS for BVPS-1 and 2 have sufficient margin to satisfy SG makeup flow requirements for the uprated plant. However, the licensee found that the valve trim for the feedwater regulating valves (FRVs) would have to be modified in order to accommodate the increased feedwater flow rate. The licensee concluded that with the requisite valve trim changes, the CFS will be fully capable of satisfying the feedwater flow requirements for EPU operation.

Excessive feedwater flow rates through the feedwater heaters can result in premature tube failure and consequential loss of feedwater transients, posing increased challenges to reactor safety systems. The licensee evaluated the feedwater flow velocity through the feedwater heater tubes and determined that it will not exceed the maximum velocity that is allowed by the Heat Exchanger Institute standards for closed feedwater heaters. The licensee also confirmed that the maximum feedwater temperature and pressure for the uprated plant will remain bounded by the existing heater design specifications.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability and reliability of the CFS to provide feedwater to the steam generators for EPU operation. Because the CPs and FPs have sufficient margin to accommodate the increased feedwater flow requirements for EPU operation, required CFS modifications are rather minor (involving valve trim replacement for the FRVs), and system design specifications will not be exceeded due to EPU operation, the staff finds that the reliability and stability of the CFS should not be adversely affected by EPU operating conditions. Furthermore, any problems related to CFS performance will be readily apparent during EPU power ascension. The licensee has not requested NRC review and approval of any changes to the CFS licensing basis relative to EPU operation and this evaluation does not constitute NRC approval of any changes to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the CFS and finds that the CFS will remain capable of providing feedwater to the SGs without creating unacceptable fluid flow instabilities and increased challenges to reactor safety systems. Also, EPU power ascension will provide additional assurance that problems of this nature will not be introduced by the proposed power uprate. Therefore, the CFS will continue to satisfy licensing-basis considerations and the proposed EPU is considered to be acceptable with respect to the CFS.

2.5.6 Waste Management Systems

2.5.6.1 Gaseous Waste Management Systems

Regulatory Evaluation

Gaseous waste management systems (GWMSs) involve the gaseous radwaste system, which deals with the management of radioactive gases collected in the offgas system or the waste gas storage and decay tanks. In addition, it involves the management of effluents from the condenser air removal system, the SG blowdown flash tank, the containment purge exhaust, and building ventilation system exhausts. The NRC staff's review of the GWMS focuses on the effects that the proposed EPU may have on methods of treatment; expected releases; principal parameters used in calculating releases of radioactive materials in gaseous effluents; and the accumulation and management of explosive mixtures. The acceptance criteria for the GWMS that are most applicable to the staff's review of proposed power uprates are based on (1) 10 CFR 20.1302, insofar as it places specific limitations on the annual average concentrations of radioactive materials released at the boundary of the unrestricted area; (2) 10 CFR Part 50, Appendix A, GDC 60, "Control of Releases of Radioactive Materials," insofar as it specifies that the plant design include means to control the release of radioactive effluents; (3) 10 CFR Part 50, Appendix A, GDC 61, "Fuel Storage and Handling and Radioactivity Control," insofar as it specifies that systems that contain radioactivity be designed with suitable shielding and filtration; (4) 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for meeting the "as low as is reasonably achievable" criterion; and (5) other licensing-basis considerations that apply. The staff's review of the GWMS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 11.2.3 of the UFSAR for BVPS-1 and Section 11.3 of the UFSAR for BVPS-2, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the capability of the GWMS to collect and process gaseous radwaste is provided in Sections 5.11.6, 9.8, and 9.24 of the BVPS-1 and 2 EPULR. The licensee determined that the EPU will result in a slight increase in the equilibrium radioactivity in the reactor coolant, which results in an increased concentration of radioactive nuclides in the radwaste system. The licensee found that the existing GWMS will remain capable of processing this increase in radioactive nuclide concentration.

Radiological and environmental monitoring of the waste streams is not affected by the proposed EPU and no new or different radiological release paths will be introduced. However, the proposed EPU will result in an increase in the activity associated with gaseous radwaste and therefore, radiological releases and offsite doses will be impacted. The licensee used the methodology outlined in NUREG-0017, Revision 0, to estimate the change in coolant and steam activity due to EPU. Based on a comparison of plant coolant system parameters for plant operation at both the pre-uprate and post-uprate conditions, the licensee established conservative scaling factors for determining the impact of the proposed power uprate on radwaste effluents and projected doses. The licensee found that gaseous release of Kr-85 will increase by approximately the percentage of the power increase, while isotopes with shorter half-lives will have varying EPU increase percentages up to a maximum of 18 percent. The licensee determined that the projected average radiological doses for EPU operation will remain well below those allowed by 10 CFR Part 20 and continue to be a small percentage of the allowable 10 CFR Part 50, Appendix I doses.

Both BVPS-1 and 2 monitor gas flow for oxygen content. The compressors that direct gas to the surge tank are shut off whenever there is an indication of high oxygen content. This precaution effectively prevents an explosive mixture of oxygen and hydrogen from accumulating and it will continue to be used for EPU operation.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the GWMS to perform its functions. Because the increase in offsite dose will be relatively small and the doses will remain a small fraction of the allowable Appendix I doses, the staff agrees that the capabilities of the GWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate. The licensee has not requested NRC review and approval of any changes to the GWMS licensing basis relative to EPU operation and this evaluation does not constitute NRC approval of any changes to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the GWMS to perform its functions and finds that the GWMS will continue to control the release of radioactive materials and preclude the possibility of waste gas explosions in accordance with the plant licensing basis. Therefore, the NRC staff concludes that the GWMS will continue to satisfy the requirements specified in 10 CFR 20.1302 and 10 CFR Part 50, Appendix I, and the criteria specified by 10 CFR Part 50, Appendix A, GDCs 60 and 61. Consequently, the proposed EPU is considered to be acceptable with respect to the GWMS.

2.5.6.2 Liquid Waste Management Systems

Regulatory Evaluation

The liquid waste management system (LWMS) consists of process equipment and instrumentation necessary to collect, process, monitor and recycle/dispose of liquid radioactive waste. Major component in the system include the waste disposal evaporator, distillate demineralizers, transfer pumps and various waste system tanks used for collecting, holdup, and processing of the waste streams. The NRC staff's review of LWMS focuses on the effects that the proposed EPU may have on previous analyses and considerations related to the processing and management of liquid radioactive waste; methods of treatment; expected releases; and principal parameters used in calculating the release of radioactive materials in liquid effluents. The acceptance criteria for the LWMS that are most applicable to the staff's review of proposed power uprates are based on (1) 10 CFR 20.1302, insofar as it places specific limitations on the annual average concentrations of radioactive materials released at the boundary of the unrestricted area; (2) 10 CFR Part 50, Appendix A, GDC 60, insofar as it specifies that the plant design include means to control the release of radioactive effluents; (3) 10 CFR Part 50, Appendix A, GDC 61, insofar as it specifies that systems that contain radioactivity be designed with suitable confinement, shielding, and filtration; (4) 10 CFR Part 50, Appendix I, Sections II.A and II.D, which set numerical guides for meeting the "as low as is reasonably achievable" criterion; and (5) other licensing-basis considerations that apply. The staff's review of the LWMS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 11.2.4 of the UFSAR for BVPS-1 and

Section 11.2 of the UFSAR for BVPS-2, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the capability of the LWMS to collect and process gaseous radwaste is provided in Sections 5.11.6, 9.8, and 9.24 of the BVPS-1 and 2 EPULR. The licensee determined that the proposed power uprate will not require any changes in the operation or design of the equipment used in the LWMS, the radiological and environmental monitoring of the waste streams will not be affected, and no new or different radiological release paths will be introduced as a result of the proposed power uprate. Since the design and operation of the LWMS will not change, and the volume of fluid flowing into the liquid radwaste system will not increase significantly as a result of EPU, the licensee concluded that the capacity of the LWMS will continue to be adequate.

The licensee evaluated the impact of the proposed power uprate on the LWMS using the methodology outlined in NUREG-0017, Revision 0, to estimate the change in coolant and steam activity due to EPU. Based on a comparison of plant coolant system parameters for plant operation at both the pre-uprate and uprated conditions, the licensee established conservative scaling factors to determine the impact that the EPU will have on radwaste liquid effluents and projected doses. The licensee found that EPU will result in an increase of approximately 14 percent in the liquid effluent release concentrations, and that the projected doses will remain well below those allowed by 10 CFR Part 20 and continue to remain a small percentage of the doses allowed by 10 CFR Part 50, Appendix I.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the LWMS to perform its functions. Because the increase in offsite dose will be relatively small and the doses will remain a small fraction of the allowable Appendix I doses, the staff agrees that the capabilities of the LWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate. The licensee has not requested NRC review and approval of any changes to the LWMS licensing basis relative to EPU operation and this evaluation does not constitute NRC approval of any changes to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the LWMS to perform its functions and finds that the LWMS will continue to control the release of radioactive materials in accordance with licensing-basis considerations. Therefore, the proposed EPU is acceptable with respect to the LWMS.

2.5.6.3 Solid Waste Management Systems

Solid radioactive waste consists of wet and dry waste. Wet waste consists mostly of low specific activity spent secondary and primary resins and filters, and oil and sludge from various

contaminated systems. The NRC staff's review relates primarily to the wet waste dewatering and liquid collection processes, and focuses on the impact that the proposed power uprate will have on the release of radioactive material to the environment via gaseous and liquid effluents. Because this is a subset of the evaluations performed in Sections 2.5.6.1 and 2.5.6.2 of this SE, a separate evaluation of solid waste management systems is not required.

2.5.7 Additional Considerations

2.5.7.1 Emergency Diesel Generator (EDG) Fuel Oil Storage and Transfer System

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions (e.g., diesel engine-driven generator sets). The NRC staff's review focuses on increases in EDG electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function. Because the EDG fuel oil storage requirements for BVPS-1 and 2 are based on the amount of fuel oil that is consumed by the respective EDGs when they are operating at their fully loaded design rating, and the EDG electrical loads for EPU operation will not exceed the EDG full load rating for either of the BVPS units, the fuel oil storage requirements for BVPS-1 and 2 are not affected by the proposed power uprate. Therefore, an evaluation of the EDG fuel oil storage requirements is not required.

2.5.7.2 Light Load Handling System (Related to Refueling)

The light load handling system (LLHS) includes components and equipment used for handling new fuel at the receiving station and for loading spent fuel into shipping casks. Because the post-EPU fuel is of the same overall dimensions and weight as the pre-EPU fuel, this area of review is not affected by the proposed power uprate and therefore, an evaluation of the LLHS is not required.

2.5.8 Fire Protection

<u>Regulatory Evaluation</u>

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The NRC staff's review focused on the effects of the increased decay heat on the plant's safe-shutdown analysis to ensure that SSCs required for the safe-shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe-shutdown following a fire. The NRC's acceptance criteria for the FPP are based on (1) 10 CFR 50.48 and associated Appendix R to 10 CFR Part 50, insofar as they require the development of an FPP to ensure, among other things, the capability to safely shutdown the plant; (2) GDC 3, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; and (3) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions.

Specific review criteria are contained in SRP Section 9.5.1, as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of RS-001.

Technical Evaluation

RS-001, Revision 0, Attachment 2 to Matrix 5, "Supplemental Fire Protection Review Criteria," states that "... power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire... where licensees rely on less than full capability systems for fire events..., the licensee should provide specific analyses for fire events that demonstrate that (1) fuel integrity is maintained by demonstrating that the fuel design limits are not exceeded and (2) there are no adverse consequences on the reactor pressure vessel integrity or the attached piping. Plants that rely on alternative/dedicated or backup shutdown capability for post-fire safe-shutdown should analyze the impact of the power uprate on the alternative/dedicated or backup shutdown capability... The licensee should identify the impact of the power uprate on the plant's post-fire safe-shutdown procedures." Section 5.12, "Fire Protection Safe Shutdown (Appendix R)" of the BVPS-1 and 2 EPULR satisfactorily addresses these fire protection requirements of the RS-001, Revision 0. The results of the Appendix R evaluation provided in Section 5.12 of the EPULR demonstrate that the plant can be brought to a cold-shutdown condition following a fire in any plant area.

The information provided in this section, as supplemented in response to the NRC staff's RAIs, satisfactorily demonstrates the licensee's compliance. Further, the licensee indicated that the compliance with the fire protection and safe-shutdown program will not be affected because the EPU evaluation did not identify changes to design or operating conditions that will adversely impact the post-fire safe-shutdown capability. The EPU evaluation does not change the credited equipment necessary for post-fire safe-shutdown nor does it reroute essential cables or relocate essential components/equipment credited for post-fire safe-shutdown. The licensee has made no significant changes to the plant configuration or combustible loading as a result of modifications necessary to implement the EPU. Any changes will be evaluated by the licensee under the plant's existing NRC-approved fire protection plan.

Conclusion

The NRC staff has reviewed the licensee's fire-related safe-shutdown assessment and concludes that the licensee has adequately accounted for the effects of the increased decay heat on the ability of the required systems to achieve and maintain safe-shutdown conditions. The staff further concludes that the FPP will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, and GDCs 3 and 5 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to fire protection.

2.6 Containment Review Considerations

2.6.1 Primary Containment Functional Design

Regulatory Evaluation

The containment encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. The NRC staff's review covered the pressure and temperature conditions in the containment due to a spectrum of postulated LOCAs and secondary system line breaks. The NRC's acceptance criteria for primary containment functional design are based on (1) GDC 16, insofar as it requires that reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment; (2) GDC 50, insofar as it requires that the containment and its internal components be able to accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA; (3) GDC 38, insofar as it requires that the containment heat removal system(s) function to rapidly reduce the containment pressure and temperature following any LOCA and maintain them at acceptably low levels; (4) GDC 13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation and accident conditions; and (5) GDC 64, insofar as it requires that means be provided for monitoring the plant environs for radioactivity that may be released from normal operations and postulated accidents. Specific review criteria are contained in SRP Section 6.2.1.1.A.

Technical Evaluation

The licensee addressed containment functional design at EPU conditions as part of the BVPS-1 and 2 containment conversion from subatmospheric to atmospheric containments. The NRC approved the containment conversion in Amendment Nos. 271 and 153, for BVPS-1 and 2, respectively, dated February 6, 2006 (ADAMS Accession Number ML060100325).

Conclusion

The NRC staff has reviewed the licensee's assessment of the containment pressure and temperature transient and concludes that the licensee has adequately accounted for the increase of mass and energy that would result from the proposed EPU. The staff further concludes that containment systems will continue to provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained. The staff also concludes that the containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and will continue to meet the requirements of GDCs 13, 16, 38, 50, and 64 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to containment functional design.

2.6.2 Subcompartment Analyses

Regulatory Evaluation

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The

NRC staff's review for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The staff's review focused on the effects of the increase in mass and energy release into the containment due to operation at EPU conditions, and the resulting increase in pressurization. The NRC's acceptance criteria for subcompartment analyses are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects, and (2) GDC 50, insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments. Specific review criteria are contained in SRP Section 6.2.1.2.

Technical Evaluation

The licensee addressed subcompartment analyses at EPU conditions as part of the BVPS-1 and 2 containment conversion from subatmospheric to atmospheric containments. The NRC approved the containment conversion in Amendment Nos. 271 and 153, for BVPS-1 and 2, respectively, dated February 6, 2006.

Conclusion

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased mass and energy release. The staff concludes that containment SSCs important to safety will continue to be protected from the dynamic effects resulting from pipe breaks and that the subcompartments will continue to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed EPU. Based on this, the staff concludes that the plant will continue to meet GDCs 4 and 50 for the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to subcompartment analyses.

2.6.3 Mass and Energy Release

2.6.3.1 Mass and Energy Release Analysis for Postulated Loss-of-Coolant Accidents (LOCAs)

Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including subcompartments and systems within the containment. The NRC staff's review covered the energy sources that are available for release to the containment and the mass and energy release rate calculations for the initial blowdown phase of the accident. The NRC's acceptance criteria for mass and energy release analyses for postulated LOCAs are based on (1) GDC 50, insofar as it requires that sufficient conservatism be provided in the mass and energy release analysis to assure that containment

design margin is maintained and (2) 10 CFR Part 50, Appendix K, insofar as it identifies sources of energy during a LOCA. Specific review criteria are contained in SRP Section 6.2.1.3.

Technical Evaluation

The licensee addressed mass and energy release analysis for postulated loss of coolant at EPU conditions as part of the BVPS-1 and 2 containment conversion from subatmospheric to atmospheric containments. The NRC approved the containment conversion in Amendment Nos. 271 and 153, for BVPS-1 and 2, respectively, dated February 6, 2006.

Conclusion

The NRC staff has reviewed the licensee's mass and energy release assessment and concludes that the licensee has adequately addressed the effects of the proposed EPU and appropriately accounts for the sources of energy identified in 10 CFR Part 50, Appendix K. Based on this, the staff finds that the mass and energy release analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative. Therefore, the staff finds the proposed EPU acceptable with respect to mass and energy release for postulated LOCA.

2.6.3.2 Mass and Energy Release Analysis for Secondary System Pipe Ruptures

Regulatory Evaluation

The NRC staff's review covered the energy sources that are available for release to the containment, the mass and energy release rate calculations, and the single-failure analyses performed for steam and feedwater line isolation provisions, which would limit the flow of steam or feedwater to the assumed pipe rupture. The NRC's acceptance criteria for mass and energy release analysis for secondary system pipe ruptures are based on GDC 50, insofar as it requires that the margin in the design of the containment structure reflect consideration of the effects of potential energy sources that have not been included in the determination of peak conditions, the experience and experimental data available for defining accident phenomena and containment response, and the conservatism of the model and the values of input parameters. Specific review criteria are contained in SRP Section 6.2.1.4.

Technical Evaluation

The licensee addressed mass and energy release analysis for postulated secondary system pipe ruptures at EPU conditions as part of the BVPS-1 and 2 containment conversion from subatmospheric to atmospheric containments. The NRC approved the containment conversion in Amendment Nos. 271 and 153, for BVPS-1 and 2, respectively, dated February 6, 2006.

Conclusion

The NRC staff has reviewed the mass and energy release assessment performed by the licensee for postulated secondary system pipe ruptures and finds that the licensee has adequately addresses the effects of the proposed EPU. Based on this, the staff concludes that the analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative

(i.e., that the analysis includes sufficient margin). Therefore, the staff finds the proposed EPU acceptable with respect to mass and energy release for postulated secondary system pipe ruptures.

2.6.4 Combustible Gas Control in Containment

Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excessive hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The NRC staff's review covered (1) the production and accumulation of combustible gases, (2) the capability to prevent high concentrations of combustible gases in local areas, (3) the capability to monitor combustible gas concentrations, and (4) the capability to reduce combustible gas concentrations. The staff's review primarily focused on any impact that the proposed EPU may have on hydrogen release assumptions, and how increases in hydrogen release are mitigated. The NRC's acceptance criteria for combustible gas control in containment are based on (1) 10 CFR 50.44, insofar as it requires that plants be provided with the capability for controlling combustible gas concentrations in the containment atmosphere; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; (3) GDC 41, insofar as it requires that systems be provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure that containment integrity is maintained; (4) GDC 42, insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic inspection; and (5) GDC 43, insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic testing. Specific review criteria are contained in SRP Section 6.2.5.

Technical Evaluation

The licensee addressed combustible gas control in containment at EPU conditions as part of the BVPS-1 and 2 containment conversion from subatmospheric to atmospheric containments. The NRC approved the containment conversion in Amendment Nos. 271 and 153, for BVPS-1 and 2, respectively, dated February 6, 2006.

Conclusion

The NRC staff has reviewed the licensee's assessment related to combustible gas and concludes that the plant will continue to have sufficient capabilities, consistent with the requirements in 10 CFR 50.44, 10 CFR 50.46, and GDCs 5, 41, 42, and 43 as discussed above. Therefore, the staff finds the proposed EPU acceptable with respect to combustible gas control in containment.

2.6.5 Containment Heat Removal

Regulatory Evaluation

Fan cooler systems, spray systems, and RHR systems are provided to remove heat from the containment atmosphere and from the water in the containment sump. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler heat exchangers. The NRC's acceptance criteria for containment heat removal are based on GDC 38, insofar as it requires that the containment heat removal system be capable of rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. Specific review criteria are contained in SRP Section 6.2.2 as supplemented by Draft Guide (DG) 1107.

Technical Evaluation

The licensee addressed containment heat removal at EPU conditions as part of the BVPS-1 and 2 containment conversion from subatmospheric to atmospheric conditions. The NRC approved the containment conversion in Amendment Nos. 271 and 153, for BVPS-1 and 2, respectively, dated February 6, 2006.

Conclusion

The NRC staff has reviewed the containment heat removal systems assessment provided by the licensee and concludes that the licensee has adequately addressed the effects of the proposed EPU. The staff finds that the systems will continue to meet GDC 38 for rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. Therefore, the staff finds the proposed EPU acceptable with respect to containment heat removal systems.

2.6.6 Pressure Analysis for ECCS Performance Capability

Regulatory Evaluation

Following a LOCA, the ECCS will supply water to the reactor vessel to reflood, and thereby cool the reactor core. The core flooding rate will increase with increasing containment pressure. The NRC staff reviewed analyses of the minimum containment pressure that could exist during the period of time until the core is reflooded to confirm the validity of the containment pressure used in ECCS performance capability studies. The staff's review covered assumptions made regarding heat removal systems, structural heat sinks, and other heat removal processes that have the potential to reduce the pressure. The NRC's acceptance criteria for the pressure analysis for ECCS performance capability are based on 10 CFR Part 50.46, insofar as it requires the use of an acceptable ECCS evaluation model that realistically describes the behavior of the reactor during LOCAs or an ECCS evaluation model developed in conformance with 10 CFR Part 50, Appendix K. Specific review criteria are contained in SRP Section 6.2.1.5.

Technical Evaluation

By letter dated October 4, 2004, the licensee provided its best-estimate large break loss-of-coolant accident (BELOCA) analyses for BVPS-1 and 2. The BELOCA analyses use NRC-approved Westinghouse methods described in Topical Report WCAP-12945-P-A, Volumes 1 through 5. These methods include an acceptable treatment of the minimum containment

pressure that could exist during the period of time until the core is reflooded. These analyses assume an atmospheric containment and EPU conditions. The NRC approved the best estimate analyses for BVPS-1 and 2 in Amendment Nos. 272 and 154 for BVPS-1 and 2 dated February 6, 2006 (ADAMS Accession Number ML060120145).

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed EPU would have on the minimum containment pressure analysis and concludes that the licensee has adequately addressed this area of review to ensure that the requirements in 10 CFR 50.46 regarding ECCS performance will continue to be met following implementation of the proposed EPU. Details of the staff's review are contained in the February 6, 2006, SE associated with Amendment Nos. 272 and 154 for BVPS-1 and 2. Therefore, the staff finds the proposed EPU acceptable with respect to minimum containment pressure for ECCS performance.

2.7 Habitability. Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

The NRC staff reviewed the control room habitability system and control building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. A further objective of the staff's review was to ensure that the control room can be maintained as the backup from which technical support personnel can safely operate the plant in the event of an accident. The staff's review focuses on the effects of the proposed EPU on the radiation doses, toxic gas concentration, and estimates of dispersion of airborne contamination. The NRC's acceptance criteria for the control room habitability system are based on: (1) GDC 4 for accommodating the effects of and being compatible with postulated accidents, including the effects of the release of toxic gases; and (2) GDC 19 for maintaining the control room in a safe, habitable condition during accidents by providing adequate protection against radiation and toxic gases. Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of RS-001.

Technical Evaluation

In its response to the NRC staff's request for additional information the licensee stated, and the staff agrees, that the function of the control room habitability system is to ensure that operator exposure following a design-basis accident remains within regulatory limits. The impact of EPU on post-accident operator exposure is summarized in Section 5.11.9 of the BVPS-1 and 2 EPULR. The licensee stated in the report that the design-basis accidents applicable to the BVPS licensing basis were re-analyzed to reflect the EPU, full implementation of an alternative source term in accordance with RG 1.183 and RSGs at BVPS-1. The evaluation in the report concludes that, following EPU, the dose consequences to the operator remain within the requirements of 10 CFR 50.67. The licensee further stated that the EPU does not affect the normal ambient conditions inside the control room during non-radiological conditions (i.e., fire or toxic release).

The licensee also stated that post-accident iodine loading on the intake charcoal filter in the control room ventilation system following EPU was assessed in support of containment conversion at EPU conditions and submitted for NRC review in the licensee's LAR dated June 2, 2004. The design-basis accident analyzed was the LOCA, which is the bounding accident for radioactive releases to the environment. In accordance with the licensee's assertion, this is documented Section 5.3.2.3 of Enclosure 2 of the licensee's June 2, 2004, containment conversion LAR. The control room ventilation intake charcoal filter iodine loading is well below the RG 1.52 acceptance criterion of 2.5 milligrams iodine per gram charcoal. The NRC staff finds this acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the control room habitability system to protect plant operators against the effects of accidental releases of toxic and radioactive gases. The staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from the proposed EPU and the staff further concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed EPU.

Based on this, the NRC staff concludes that the control room habitability system will continue to meet the requirements of GDCs 4 and 19. Therefore, the staff finds the proposed EPU acceptable with respect to the control room habitability system.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

Regulatory Evaluation

Engineered safety feature (ESF) atmosphere cleanup systems are designed for fission product removal in post-accident environments. These systems generally included primary systems (e.g., in-containment recirculation) and secondary systems (e.g., emergency or post-accident air-cleaning systems) for the fuel-handling building, control room, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the NRC staff's review focuses on the effects of the proposed EPU on system functional design; environmental design; and provisions to inhibit off-design temperatures in the adsorber section. The NRC's acceptance criteria for the ESF atmosphere cleanup systems are based on: (1) GDC 19 for the design of systems for habitability of the control room under accident conditions; (2) GDC 41 for the design of systems to be used for containment atmosphere cleanup following postulated accidents and to control releases to the environment; (3) GDC 61 for the design of systems for radioactivity control under normal and postulated accident conditions; and (4) GDC 64 for monitoring radioactive releases from ESF atmosphere cleanup systems under normal, anticipated operational occurrences, and postulated accident conditions. Specific review criteria are contained in SRP Section 6.5.1.

Technical Evaluation

The ESF atmospheric cleanup systems are described in the BVPS-1 UFSAR, Section 6.6 and the BVPS-2 UFSAR, Section 6.5.1. The BVPS-1 and 2 supplementary leak collection and release systems (SLCRSs) have been reviewed to support operation at EPU conditions in conjunction with the containment conversion.

The BVPS-1 SLCRS consists of two 100-percent capacity leak collection exhaust fans. Air is exhausted from the fuel building, waste gas storage area, blowdown tank room, personnel access hatch area, purge air duct area, cable vaults, pipe tunnel, and north and west safeguards areas, and is exhausted from the containment during refueling.

The BVPS-2 SLCRS is comprised of 2 subsystems:

1. The supplementary leak collection normal exhaust system (non-safety-related)
2. The supplementary leak collection filtered exhaust system (safety-related).

During normal plant operation, the normal exhaust fan is manually set to exhaust unfiltered air from the SLCRS areas, except for the solid waste handling building, auxiliary building, charging pump cubicles, cable vaults, component cooling water pump area, and the fuel building. The exhaust air from the excepted SLCRS areas is demisted, filtered, and exhausted by the filtered exhaust fans.

The licensee stated that BVPS-1 and 2 SLCRSs were evaluated for impact resulting from operation at the EPU power level in conjunction with containment conversion, both with and without charcoal filters. The effect of power uprate on heat loads in areas exhausted by the SLCRSs is addressed and found acceptable by the licensee in Section 9.7.2 of the EPULR.

Additionally, the licensee documented in Enclosure 2 of the containment conversion LAR, that the post-LOCA iodine loading on the SLCRS ventilation exhaust charcoal filter following EPU and containment conversion remains well below the RG 1.52 acceptance criterion. As discussed under SRP Section 6.4, the LOCA is the bounding accident for radioactive releases to the environment.

The licensee also stated that there are no system design or operation changes required relative to the operation of the SLCRSs at EPU conditions following containment conversion. The licensee found that BVPS-1 and 2 SLCRSs are capable of achieving post-accident design and licensing requirements for operation at EPU conditions, including operation in conjunction with an atmospheric containment design, either with or without HEPA or charcoal filters installed in the filtration assemblies. Based on the above, the NRC staff finds that operation of the SCLRSs at EPU conditions will be adequate with respect to heat loading and post-LOCA iodine loading of the charcoal filters and is therefore, acceptable.

Conclusion

The NRC staff has reviewed the licensee’s assessment of the effects of the proposed EPU on the ESF atmosphere cleanup systems. The staff concludes that the licensee has adequately accounted for the increase in fission products and changes in expected environmental conditions that would result from the proposed EPU, and the staff further concludes that the ESF atmosphere cleanup systems will continue to provided adequate fission product removal in post-accident environments following implementation of the proposed EPU. Based on this information, the staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of GDCs 19, 41, 61, and 64. Therefore, the staff finds the proposed EPU acceptable with respect to the ESF atmosphere cleanup systems.

2.7.3 Ventilation Systems

2.7.3.1 Control Room Area Ventilation System

Regulatory Evaluation

The function of the control room area ventilation system (CRAVS) is to provide a controlled environment for the comfort and safety of control room personnel, and to support the operability of control room components during normal operation, anticipated operational occurrences, and design-basis accident conditions. The NRC staff's review of the CRAVS focuses on the effects that the proposed EPU will have on the functional performance of safety-related portions of the system. The review includes the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the CRAVS. The NRC's acceptance criteria for the CRAVS are based on: (1) GDC 4 for the CRAVS being designed to accommodate the effects of, and to be compatible with, anticipated environmental conditions; (2) GDC 19 for providing adequate protection to permit access and occupancy of the control room under accident conditions; and (3) GDC 60 for the system's capability to suitably control releases of gaseous radioactive effluents to the environment. Specific review criteria are contained in SRP Section 9.4.1.

Technical Evaluation

For this system, the licensee stated that the EPU does not affect the normal ambient conditions inside the control room and the temperatures do not increase as a result of the EPU. The licensee also stated that there are no changes to the CRAVS due to EPU for the following:

(a) Discharge of airborne contaminants inside the control room.

(b) Detection and isolation capabilities.

(c) Degraded system performance.

(d) Internal or external flood protection.

(e) Fire protection.

(f) Internal or external missiles.

(g) High-energy pipe breaks.

Based on the above, the NRC staff finds that there will not be significant changes to operation of the CRAVS as a result of the EPU, and the CRAVS will continue to meet the applicable GDCs.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of control room personnel; and to support the operability of control room components. The staff

concludes that the licensee has adequately accounted for the increases of toxic and radioactive gases that would result from the proposed EPU and changes to parameters affecting environmental conditions for control room personnel and equipment. The staff concludes that the CRAVS will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed EPU. The staff also concludes that the system will continue to suitably control the releases of gaseous radioactive effluents to the environment. Based on this review, the staff concludes that the CRAVS will continue to meet the requirements of GDCs 4, 19, and 60. Therefore, the staff finds the proposed EPU acceptable with respect to the CRAVS.

2.7.3.2 Spent Fuel Pool Area Ventilation System (SFPAVS)

Regulatory Evaluation

The function of the SFPAVS is to maintain ventilation in the spent fuel pool equipment areas, to permit personnel access, and to control airborne radioactivity in the area during normal operation, anticipated operational occurrences, and following postulated fuel handling accidents. The NRC staff's review focuses on the effects of the proposed EPU on the functional performance of the safety-related portions of the systems. The NRC's acceptance criteria for the SFPAVS are based on: (1) GDC 6 for the system's capability to suitably control release of gaseous radioactive effluents to the environment; and (2) GDC 61 for the system's capability to provide appropriate containment. Specific review criteria are contained in SRP Section 9.4.2.

Technical Evaluation

In response to the NRC staff's RAI, the licensee stated that the SFPAVS is discussed in Section 9.22.3 of the BVPS-1 and 2 EPULR as not requiring any change for operation at EPU conditions. The SFPAVS is described in the BVPS-1 UFSAR, Section 9.13.3 and the BVPS-2 UFSAR, Section 9.4.2. Amendment Nos. 247 and 126 were issued by the NRC to allow core off-loads after 100 hours of decay time. The analyses supporting the amendment requests were done for a core power of 2900 MWt. Due to administrative control of fuel movement and fuel pool water temperatures, the EPU does not affect the normal ambient conditions inside the spent fuel pool area. Based on the results of the NRC staff's review of the information provided by the licensee, the staff finds that operation of the SFPAVS will not be adversely impacted by the EPU, and will continue to meet the applicable GDCs and is therefore, acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SFPAVS. The staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's capability to maintain ventilation in the spent fuel pool equipment areas, to permit personnel access, control airborne radioactivity in the area, control release of gaseous radioactive effluents to the environment, and provide appropriate containment. Based on the above, the staff concludes that the SFPAVS will continue to meet the requirements of GDCs 60 and 61. Therefore, the staff finds the proposed EPU acceptable with respect to the SFPAVS.

2.7.3.3 Auxiliary and Radwaste Area and Turbine Area Ventilation Systems

Regulatory Evaluation

The function of the auxiliary and radwaste area ventilation system (ARAVS) and the turbine area ventilation system (TAVS) is to maintain ventilation in the auxiliary and radwaste equipment and turbine areas, to permit personnel access, and to control the concentration of airborne radioactive material in these areas during normal operation, during anticipated operational occurrences, and after postulated accidents. The NRC staff's review focuses on the effects of the proposed EPU on the functional performance of the safety-related portions of these systems. The NRC's acceptance criteria for the ARAVS and TAVS are based on GDC 60 for the capability of these systems to suitably control release of gaseous radioactive effluents to the environment. Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4.

Technical Evaluation

For BVPS-1, the licensee stated that the auxiliary building ventilation system is designed to provide a suitable environment for personnel and equipment and prevent the spread of radioactive contamination. The ventilation exhaust air from areas subject to radioactive contamination, including the radwaste areas, are designed with provision for diverting the flow through the main filter banks in the supplementary leak collection and release system.

For BVPS-2, the auxiliary building ventilation system provides an environment suitable for personnel and equipment operation, and minimizes the potential for spread of airborne radioactive material within the building during normal operation.

The radwaste area ventilation system is an extension of the auxiliary building ventilation system. It removes heat dissipated into the building from machinery, piping, lighting, and the environment, maintains an environment suitable for personnel access and equipment operation, and minimizes the potential for the spread of radioactive airborne particulates within the building.

For both units, the licensee stated that the temperature in the auxiliary and radwaste areas do not increase as a result of the EPU. The impact of power uprate on the ARAVSs does not adversely affect the operational capability of these systems. The systems will function as designed under power uprate conditions.

The turbine building area ventilation systems remove heat dissipated by equipment, piping, lighting, and solar heat gains and maintains an environment suitable for personnel access and equipment operation in the turbine building. The system uses outside air as the cooling medium.

The turbine building houses the following pumps with increased flowrates for operation at EPU conditions:

BVPS-1 Turbine Building	BVPS-2 Turbine Building
Condensate Pumps	Condensate Pumps
Feedwater Pumps	Feedwater Pumps
Heater Drain Pumps	Heater Drain Pumps
Turbine Plant Cooling Pumps	Turbine Component Cooling Pumps

Separator Drain Pumps

In addition, piping in the condensate, feedwater, heater drain, and extraction steam systems will be slightly hotter at EPU conditions.

The change in heat loads due to EPU conditions from piping and motors can be accommodated by the existing ventilation system capabilities for the turbine building ventilation systems without exceeding the design temperatures, and are, therefore, acceptable under EPU conditions. Because the radwaste and auxiliary ventilation areas are unaffected by the proposed EPU, and because the turbine building ventilation systems can easily accommodate the slight additional heat load as a result of the EPU, the NRC staff finds that operation of the ARAVS and TAVS at EPU conditions is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ARAVS and TAVS. The staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the capability of these systems to maintain ventilation in the auxiliary and radwaste equipment areas and in the turbine area, permit personnel access, control the concentration of airborne radioactive material in these areas, and control release of gaseous radioactive effluents to the environment. Based on this, the staff concludes that the ARAVS and TAVS will continue to meet the requirements of GDC 60. Therefore, the staff finds the proposed EPU acceptable with respect to the ARAVS and the TAVS.

2.7.3.4 Engineered Safety Feature Ventilation System (ESFVS)

Regulatory Evaluation

The function of the ESFVS is to provide a suitable and controlled environment for ESF components following certain anticipated transients and design-basis accidents. The NRC staff's review for the ESFVS focuses on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The staff's review also covers: (1) the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESFVS system performance; (2) the capability of the ESFVS to circulate sufficient air to prevent accumulation of flammable or explosive gas or fuel-vapor mixtures from components such as storage batteries and stored fuel; and (3) the capability of the system to control airborne particulate material (dust) accumulation. The NRC's acceptance criteria for the ESFVS are based on: (1) GDC 4 for the ESFVS being designed to accommodate the effects of and to be compatible with anticipated environmental conditions associated with normal operation and postulated accidents; (2) GDC 17 for ensuring proper functioning of the essential electric power system; and (3) GDC 60 for the system being able to suitably control release of gaseous radioactive effluents to the environment. Specific review criteria are contained in SRP Section 9.4.5.

Technical Evaluation

The ESFVS ventilates various areas that house ESF equipment. Most of these areas are unaffected by EPU. The ventilation systems use room coolers to provide a suitable and controlled environment for personnel and equipment, with maximum safety against the spread of radioactive contamination.

In response to the NRC staff's RAI, the licensee stated that post-accident temperatures for the ECCS equipment change little as a result of EPU. Minor heat load changes result from containment sump temperature changes. The areas affected include the recirculation spray system and low-head SI rooms, which take suction from the sump after the refueling water storage tank is depleted, and the high-head SI rooms, which recirculate containment sump water. Peak sump temperatures change slightly as the result of the EPU. These sump temperature changes include the influence of the effects of the containment conversion and the replacement steam generators for BVPS-1. As a result of the change in methodologies for the various analyses, the peak sump temperatures at EPU conditions are slightly lower than predicted in the original analyses. Therefore, the calculated heat loads and temperatures in affected areas are bounded by the original analyses and design. The ESFVS will satisfactorily support operation at EPU conditions.

The licensee stated that the emergency switchgear area houses the power breakers for BVPS-1 and 2. This includes the breakers for the containment air recirculation (CAR) fans. As a result of containment conversion, these fans have an increase in fan brake horsepower due to the increase in air density when normal operation pressure in the containment is increased.

The licensee further stated that an increase in CAR fan brake horsepower increases the current at the switchgear. The change in heat loads due to EPU conditions from the CAR fan motor horsepower changes for normal operation can be accommodated by the existing ventilation system capabilities. There is no change in fan motor horsepower under accident conditions. Therefore, the operation of emergency switchgear area ventilation systems do not exceed the design temperatures, and are, therefore, acceptable under EPU conditions. Based on the above, the NRC staff finds that the operation of the ESVFS meets the SRP acceptance criteria and is therefore, acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESFVS. The staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the ability of the ESFVS to provide a suitable and controlled environment for ESF components. The staff further concludes that the ESFVS will continue to assure a suitable environment for the ESF components following implementation of the proposed EPU. The staff also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment following implementation of the proposed EPU. Based on this, the staff concludes that the ESFVS will continue to meet the requirements of GDCs 4, 17, and 60. Therefore, the staff finds the proposed EPU acceptable with respect to the ESFVS.

2.8 Reactor Systems

2.8.1 Fuel System Design (EPULR Sections 4.3, and 6.0)

Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, top and bottom nozzles, and reactivity control rods. The NRC staff reviewed the fuel system to ensure that (1) the fuel system is not damaged as a result of normal operation and anticipated operational occurrences (AOOs), (2) fuel system damage is never so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures is not underestimated for postulated accidents, and (4) coolability is always maintained. The staff's review covered fuel system damage mechanisms, limiting values for important parameters, and performance of the fuel system during normal operation, AOOs, and postulated accidents. The NRC's acceptance criteria are based on (1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; (2) GDC 10, insofar as it requires that the reactor core be designed with appropriate margins to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of AOOs; (3) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margins for stuck rods, to assure the capability to cool the core is maintained; and (4) GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA. Specific review criteria are contained in SRP Section 4.2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

To support the EPU, the fuel assembly design was changed from the Vantage 5H (V5H) design to the Robust Fuel Assembly (RFA) design. The RFA fuel geometry/characteristics remain the same as the V5H fuel assemblies. The major change to the fuel assembly from V5H to RFA is the redesigned mid-grids, the addition of intermediate flow mixing grids, and thicker instrument and guide tubes. The BVPS cores have been completely transitioned from V5H to RFA fuel assemblies. The licensee states that previously burned V5H fuel assemblies may be reinserted as part of a cycle-specific reload pattern. The V5H fuel design is mechanically and hydraulically compatible with the RFA fuel design.

Structurally, the V5H fuel assembly design is very similar to the VANTAGE+ fuel assembly design [28]. The most significant difference is the implementation of a new cladding material, ZIRLO™. BVPS-1 and 2 received license amendments permitting the use of VANTAGE+ fuel on May 23, 1997 [29] and September 13, 1996 [30], respectively.

The RFA/RFA-2 fuel designs are modifications of the physical structure of the 17x17 VANTAGE+ fuel assembly design. The RFA/RFA-2 modifications were licensed under the Westinghouse fuel criteria evaluation process (FCEP) [31]. The FCEP is an NRC-approved process whereby Westinghouse may make minor changes to its fuel designs without prior NRC approval. Westinghouse is required to notify the NRC when such changes are made. FCEP notifications for the RFA and RFA-2 fuel designs were made to the NRC on September 30, 1998 [32] and August 31, 2001 [33], respectively. As with any other change, the licensee must then evaluate the change and implement it either by using the 10 CFR 50.59 change process or by requesting a license amendment.

Since the RFA and RFA-2 fuel systems at BVPS-1 and 2 have already been evaluated for use at the currently licensed RTP, this review will focus on the effects of the EPU.

The EPU will cause the fuel operating temperatures and the fuel assembly average burnup to increase. In addition, the best-estimate flow will increase due to (1) the RSGs for BVPS-1, and (2) the change in SG tube plugging limits for BVPS-1 and 2. Therefore, the fuel system design criteria that must be evaluated are: stress and strain, fatigue, grid-to-rod fretting, corrosion, dimensional changes, rod internal pressure, fuel assembly lift forces, and vibration.

Fuel System Damage

The licensee evaluated the EPU for its affect on fuel system damage due to clad stress and strain, corrosion, assembly grid-to-rod fretting, internal rod pressure, and hydraulic loads. The licensee used an NRC-approved fuel performance model [34]; [35]; [36] to evaluate the impact of the EPU on these criteria. The licensee's analysis shows that the EPU core will not impact the fuel's capability to meet clad stress and strain limits, and fatigue limits for the EPU conditions. The licensee's analysis also shows that the EPU's increased operating temperatures for the clad, due to the increased rod average power rating, will not impact the fuel's capability to meet corrosion limits for both the ZIRLO™ and Zircaloy-4 clad fuel. The licensee determined that the propensity for crud deposition and chemical plate-out on the cladding, with proper chemistry control, will not significantly increase under EPU conditions, and that the internal rod pressure acceptance criterion (no increase in the diametrical gap due to clad creep during steady-state operation or for DNB propagation to occur) is satisfied. Finally, the licensee determined that fuel assembly hold down spring capacity is still acceptable, given the increased up-lift force associated with the best-estimate RCS flow and the increased fuel assembly growth due to the higher assembly average burnup. Based on the results of the licensee's analysis using the NRC-approved fuel performance model which demonstrates that the EPU core will not result in fuel damage, the NRC staff finds the licensee's fuel damage assessment acceptable with respect to EPU.

Fuel Rod Failure

Internal hydriding and cladding collapse are primarily a result of deficiencies in the manufacturing process, which is not an EPU-related factor, and therefore, not considered further in this review.

Test results from the vibration investigation and pressure drop experimental research (VIPER) loop for the RFA/RFA-2 fuel designs continue to bound the BVPS-1 and 2 assemblies operating under EPU conditions. The transient analyses submitted in the EPULR demonstrate that the SAFDLs are not exceeded for normal operation and AOOs, and that the number of predicted fuel rod failures is not underestimated for postulated accidents.

Fuel Coolability

The licensee evaluated the EPU for its affect on fuel system embrittlement and fuel rod ballooning. The licensee used an NRC-approved fuel performance model [34]; [35]; [36] to evaluate the impact of the EPU on these criteria. The licensee's analysis shows that the hydrogen pickup level in the cladding will be less than the acceptance limit. The licensee determined the internal rod pressure acceptance criterion to prevent DNB propagation is met,

thereby preventing fuel rod ballooning. The transient analyses submitted in the EPULR demonstrate that the fuel system damage is never so severe as to prevent control rod insertion when it is required, that the number of predicted fuel rod failures is not underestimated for postulated accidents, and that coolability is always maintained. Based on the licensee's analysis using an NRC-approved fuel performance model which demonstrates that fuel rod ballooning is not expected to occur and control rod insertion will not be affected, the NRC staff finds the licensee's assessment of fuel coolability to be acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the fuel system design of the fuel assemblies, control systems, and reactor core. The staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the fuel system and demonstrated that (1) the fuel system will not be damaged as a result of normal operation and AOOs, (2) the fuel system damage will never be so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures will not be underestimated for postulated accidents, and (4) coolability will always be maintained. Based on this, the staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, GDCs 10, 27, and 35 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the fuel system design.

2.8.2 Nuclear Design (EPULR Section 6.2)

Regulatory Evaluation

The NRC staff reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and AOOs, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. The staff's review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation.

The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC 11, insofar as it requires that the reactor core be designed so that the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity; (3) GDC 12, insofar as it requires that the reactor core be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can be reliably and readily detected and suppressed; (4) GDC 13, insofar as it requires that instrumentation and controls be provided to monitor variables and systems affecting the fission process over anticipated ranges for normal operation, AOOs and accident conditions, and to maintain the variables and systems within prescribed operating ranges; (5) GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to automatically initiate operation of systems and components important to safety under accident conditions; (6) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (7) GDC 26, insofar as it requires that

two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (8) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (9) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core. Specific review criteria are contained in SRP Section 4.3 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The EPU and fuel system change can affect key nuclear safety parameters, such as core power distribution, reactivity coefficients, reactivity control requirements and control provisions, and reactivity worths, criticality, burnup, and vessel irradiation. Many of these parameters are used in accident analyses [3]; [8].

The licensee evaluated the BVPS-1 and 2 nuclear design bases and methodologies for the use of Westinghouse RFA/RFA-2 fuel system design considering the uprated core power level (2900 MWt RTP). The following table shows that the nuclear design parameters are not changing:

Parameter	Pre-EPU	Post-EPU
Power (MWt)	2689	2900
HFP T_{avg} (EF)	576.2	576.2[(1)]
RCS Pressure (psia)	2250	2250
Core Average Linear Heat Rate (kw/ft)	5.28	5.69
Most Positive MTC (pcm/^{o}F)	+2	+2
Most Positive MDC (ΔK/g/cm^3)	+0.43	+0.43
Doppler Temperature Coefficient (pcm/^{o}F)	-1.4 to -2.9	-1.4 to -2.9
Doppler Only Power Coefficient (pcm/%power) Least Negative	-10.18 to -5.98	-10.18 to -5.98

Doppler Only Power Coefficient (pcm/%power) Most Negative	-19.4 to -11.24	-19.4 to -11.24
Beta-Effective	.0047 to .0075	.0047 to .0075
Shutdown Margin (pcm)	1770	1770
Hot Channel Enthalpy Rise Factor $F^{N}_{\Delta H}$	1.500/1.62(2)	1.500/1.62(2)
Total Core Peaking Factor F_Q	2.40	2.40

Notes:

(1) The EPU vessel average temperature is expected to be about the same as current vessel average temperature even though the EPU design parameters in Section 2.1.1 include a vessel average temperature range of 566.2 EF to 580 EF.

(2) The core design limit including uncertainties is 1.500 and the Technical Specifications/COLR limit not including uncertainties is 1.62.

On February 27, 2006, the NRC issued Amendment Nos. 274 and 155 to BVPS-1 and 2 to permit the use of relaxed axial offset control (RAOC) [37] at BVPS-1 and 2, based, in part, on the information provided in NRC-approved Topical Report, WCAP-10216-P-A [38]. WCAP-10216-P-A contains two parts. One part describes a method for determining an acceptable axial flux differential profile. The other part describes an alternate means for monitoring the heat flux hot channel factor (F_Q).

The design of the fuel assemblies currently loaded in the BVPS-1 and 2 cores are unchanged for operation at the EPU power level. The licensee’s nuclear design analyses are based upon an assumed core power level of 2900 MWt, and typical values for the mechanical and thermal hydraulics data. With the exception of core power level, all assumed parameter values are within currently licensed limits. Furthermore, the licensee states that the final parameter values will be determined via the cycle-specific reload process [42], as a confirmation that they’re appropriate for the operating conditions of each specific cycle. The EPU physics data and other nuclear design parameter values are verified to be applicable to the range of fuel management patterns that are expected to exist in future core designs. The EPU does not require any changes to current nuclear design methods and models. The result is that fuel design limits would not be violated during normal operation or AOOs. Specifically, postulated reactivity accidents would not lead to a breach of the RCPB, nor jeopardize the coolability of the core. These assertions are tested and confirmed by the accident analysis results presented in the EPULR [8] as reviewed and approved by the NRC staff in Section 2.8.5 of this SE.

Conclusion

The NRC staff has reviewed the licensee’s analyses related to the effect of the proposed EPU and fuel system change on the nuclear design of the fuel assemblies, control systems, and reactor core. The staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the nuclear design and has demonstrated that the fuel design limits will not be exceeded during normal operation or AOOs, and that the effects of postulated reactivity

accidents will not cause significant damage to the RCPB or impair the capability to cool the core. Based on this evaluation and in coordination with the reviews of the fuel system design, thermal and hydraulic design, and transient and accident analyses, the staff concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the applicable requirements of GDCs 10, 11, 12, 13, 20, 25, 26, 27, and 28. Therefore, the staff finds the proposed EPU acceptable with respect to the nuclear design.

2.8.3 Thermal and Hydraulic Design (EPULR Section 6.1)

<u>Regulatory Evaluation</u>

The NRC staff reviewed the thermal and hydraulic design of the core and the RCS to confirm that the design (1) has been accomplished using acceptable analytical methods, (2) is equivalent to or a justified extrapolation from proven designs, (3) provides acceptable margins of safety from conditions which would lead to fuel damage during normal reactor operation and AOOs, and (4) is not susceptible to thermal-hydraulic instability. The review also covered hydraulic loads on the core and RCS components during normal operation and DBA conditions and core thermal-hydraulic stability under normal operation and anticipated transients without scram (ATWS) events. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; and (2) GDC 12, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can reliably and readily be detected and suppressed. Specific review criteria are contained in SRP Section 4.4 and other guidance is provided in Matrix 8 of RS-001.

<u>Technical Evaluation</u>

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 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 [27]. 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 [40]. 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 LAR No. 320 [5].

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 LAR No. 320.

In addition, the licensee used the WRB-1, W-3, and WRB-2 DNB correlations, consistent with the analyses of record. The licensee requested adoption of the WRB-2M correlation as part of this amendment request.

Thermal/hydraulic analyses are currently performed with the THINC-IV and FACTRAN codes, which have been approved by the NRC staff. The THINC-IV code performs thermal/hydraulic calculations within the fuel channels, including DNBR evaluation at the fuel pin surface. For calculations in which transient heat conduction within the fuel pins is important, this calculation is performed by FACTRAN, which describes the conductive heat transfer within the fuel pin interior and the convective heat transfer at the surface.

Both the thermal/hydraulic and the conduction/convection calculations are performed in VIPRE [43]. VIPRE can be used to determine the core limits, which can be used for reactor setpoint analysis, such as the Overtemperature ΔT (OTΔT) trip protection. 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. VIPRE has been approved [44] by the NRC staff, as a replacement for THINC-IV and FACTRAN, provided that: (1) the appropriate critical heat flux (CHF) correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters for a specific plant application are justified with each submittal, (2) conservative reactor core boundary conditions, such as core inlet coolant flow and enthalpy, core average power, power shape and nuclear peaking factors, are input to VIPRE for reactor transient analysis, and (3) the requirements for use of new CHF correlations with VIPRE are satisfied. Westinghouse has met these requirements for the WRB-1, WRB-2, and WRB-2M correlations. The DNBR limit is 1.17 for the for WRB-1 and WRB-2 correlations, and 1.14 for the WRB-2M correlation. The W-3 correlation can also be used with VIPRE. See LAR Section 2.8.1, “Fuel System Design,” for further discussion of the fuel-dependent parameters.

The thermal hydraulic evaluation at EPU conditions for BVPS-1 and 2 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 found 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 and 2. The staff also found the use of the WRB-2M correlation acceptable, since the accidents analyses, as stated in Section 2.8.5 of this SE, demonstrate that the DNB safety analysis limits (SALs) were not exceeded.

Conclusion

The NRC staff has reviewed the licensee’s analyses related to the effects of the proposed EPU on the thermal and hydraulic design of the core and the RCS. The staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the thermal and hydraulic design and demonstrated that the design (1) has been accomplished using acceptable analytical methods, (2) is equivalent to proven designs, (3) provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs, and (4) is not susceptible to thermal-hydraulic instability. The staff further concludes that the licensee has adequately accounted for the effects of the proposed EPU on the hydraulic loads on the core and RCS components. Based on this, the staff concludes that the thermal and hydraulic design will continue to meet the requirements of GDCs 10 and 12

following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to thermal and hydraulic design.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System (EPULR Sections 3.2.1, 4.4, and 9.22.3)

The NRC staff's review covered the functional performance of the control rod drive system (CRDS) to confirm that the system can effect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CRDS cooling system to ensure that it will continue to meet its design requirements. The NRC's acceptance criteria are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC 23, insofar as it requires that the protection system be designed to fail into a safe state; (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (4) GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (5) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (6) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core; and (7) GDC 29, insofar as it requires that the protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in the event of AOOs. Specific review criteria are contained in SRP Section 4.6.

Technical Evaluation

There are no physical changes to the control rod drive system, operating coil stacks, power supplies, solid state electronic control cabinets, or the control rod drive cooling system. There are no physical changes to the fuel system design that would affect the control rod drive system.

The best estimate flow is increasing due to replacement steam generators on BVPS-1, and to a change in the steam generator tube plugging limit for both BVPS units. The increased flow has the potential to impact the control rod insertion times. The licensee evaluated the impact of the EPU on control insertion times and found them to remain bounded by the current TS limit of 2.8 seconds. Control insertion times are verified after each refueling outage to be with in the TS limit, providing reasonable assurance that any impact on the control insertion times would be identified before operation.

The EPU is expected to increase vessel head temperature from 595 EF to 601.3 EF. The licensee has evaluated the impact on the CRDM and capped latch housings and determined

the stress and fatigue criteria are meet for both components. The review of the effect of the increased RV head temperature is in Section 2.1.5 of this SE.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the functional design of the CRDS. The staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system's ability to effect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents will be maintained following the implementation of the proposed EPU. The staff further concludes that the licensee has demonstrated that sufficient cooling exists to ensure the system's design bases will continue to be followed upon implementation of the proposed EPU. Based on this, the staff concludes that the fuel system and associated analyses will continue to meet the requirements of GDCs 4, 23, 25, 26, 27, 28, and 29 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the functional design of the CRDS.

2.8.4.2 Overpressure Protection During Power Operation (EPULR Sections 3.2, 5.3.6, and 9.1)

Regulatory Evaluation

Overpressure protection for the RCPB during power operation is provided by relief and safety valves and the reactor protection system (RPS). The NRC staff's review covered pressurizer relief and safety valves and the piping from these valves to the quench tank and RCS relief and safety valves. The NRC's acceptance criteria are based on (1) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs and (2) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

In a letter dated December 2, 2005 [17], the licensee provided the results of analyses to demonstrate that the BVPS-1 and 2 safety valve designs continue to be sufficient to limit RCS pressure to less than 110 percent of the RCS pressure boundary design pressure (as specified by the ASME Code [39]), during the most severe abnormal operating transient and the reactor scrammed by the second safety grade signal from the RPS with sufficient margin to account for uncertainties in design and operation of the plant. The licensee performed the analyses incorporating assumptions consistent with those specified in SRP 5.2.2, Section II.A, including the assumption that reactor scram is initiated by the second safety grade signal from the RPS [55]. The timing of the trip made little difference in the peak pressure, with the peak pressure occurring just after the safety valves opened. The calculated peak pressure continued to be less than the acceptance criteria. The NRC staff finds the analyses acceptable because the

analyses were performed consistent with the guidance provided in SRP 5.2.2, Section II.A . The staff also concludes that these analyses acceptably demonstrate that the BVPS-1 and 2 safety valves continue to have sufficient capacity at the uprated power to satisfy their requirements, as stated above.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during power operation. The staff concludes that the licensee has (1) adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features and (2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, the staff concludes that the overpressure protection features will continue to provide adequate protection to meet GDCs 15 and 31 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to overpressure protection during power operation.

2.8.4.3 Overpressure Protection During Low Temperature Operation (EPULR Sections 3.2.3, 4.1.2, 4.7.2, and 4.10

Regulatory Evaluation

Overpressure protection for the RCPB during low temperature operation of the plant is provided by pressure-relieving systems that function during the low temperature operation. The NRC staff's review covered relief valves with piping to the quench tank, the makeup and letdown system, and the RHR system which may be operating when the primary system is water solid. The NRC's acceptance criteria are based on (1) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (2) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2. The NRC staff's review also considered the effects of the vessel fluence increase due to EPU on the pressure-temperature (PT) limit curves and PTS pursuant to 10 CFR 50.61.

Technical Evaluation

PT Limit Curves:

The most recent evaluation of the fluence values for 19, 22, and 28 EFPYs have been calculated in connection with the dosimetry measurement and evaluation of Capsule Y from BVPS-1 [17]. The evaluation followed the guidance in RG 1.190. Therefore, it is acceptable.

The PT limit curve analysis for BVPS-1 is documented in WCAP-15570 [20], for 19, 22, and 28 EFPYs of operation. The fluence estimates for the proposed EPU exceed the projections performed in connection with capsule Y. The licensee adjusted the range of validity of the 22

and 28 EFPY curves to 21.78 and 27.58 EFPYs, respectively, leaving the 22 and 28 EFPY limit curves unchanged. This is acceptable, because the curves are within the range of their validity. For BVPS-2, the fluence was calculated in connection with the dosimetry measurement of surveillance capsule W and is documented in WCAP-15675 [21]. The PT limit curves are documented in WCAP-15677 [22], for 16 and 22 EFPYs. For this case, the PT curves were calculated for the EPU fluence, hence, no applicability rate adjustment is necessary.

PTS

The fluence values obtained from the Y and W capsules for both BVPS-1 and 2, respectively, are also used for the estimation of the RT_{PTS} values at the end of the current license. For BVPS-1, the lower shell plate B6903-1 is the critical element, i.e., has the highest estimated RT_{PTS} value at the end of the current license. For BVPS-1, the PTS calculations are documented in WCAP-15569 [23]. The RT_{PTS} value remains below the 10 CFR 50.61 screening criterion of 270 EF at 28 EFPYs considered the end of the current license. This is acceptable, because it satisfies 10 CFR 50.61. For BVPS-2, the PTS calculations are documented in WCAP-15676 [24], using the fluence values estimated in WCAP-15675 [21] that include the EPU effect on fluence. The RT_{PTS} value for 32 EFPYs is considerably lower than the 10 CFR 50.61 screening criterion for plates of 270 EF. As in BVPS-1, this is acceptable, because it satisfies 10 CFR 50.61. Since the PT limit curves do not change, the low temperature overpressure protection (LTOP) setpoint does not change.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during low temperature operation. The staff concludes that the licensee has (1) adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features and (2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, the staff concludes that the low temperature overpressure protection features will continue to provide adequate protection to meet GDCs 15 and 31 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to overpressure protection during low temperature operation.

2.8.4.4 Residual Heat Removal (RHR) System (EPULR Section 9.3)

Regulatory Evaluation

The RHR system is used to cool down the RCS following reactor shutdown. The RHR system is typically a low pressure system that takes over the RHR function when the RCS temperature is reduced.

The NRC staff's review covered the effect of the proposed EPU on the functional capability of the RHR system to cool the RCS following shutdown and provide decay heat removal. The NRC's acceptance criteria are based on (1) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC 34, which specifies requirements for an RHR system.

The RHR system design bases are described in Section 9.3 of the BVPS-1 UFSAR and Section 5.4.7 of the BVPS-2 UFSAR. Specific review criteria are specified in SRP Section 5.4.7, and supplemented by guidance provided in RS-001.

Technical Evaluation

The RHR system consists of 2 centrifugal pumps, 2 heat exchangers, and interconnecting piping and instrumentation. When the RHR system is in operation, the RHR pumps take suction from the RCS hot legs, route the flow through the tube side of the RHR heat exchangers, and return the flow to each of the RCS cold legs. Cooling flow to the shell side of the RHR heat exchangers is provided by the CCW system, which is cooled by the SWS.

The licensee states that RHR system design functions are not affected by EPU conditions. For BVPS-1, the RHR system is designed for normal cooldown and is not considered essential to attain safe shutdown. For BVPS-2, the RHR system is also designed for normal cooldown; but also operates, in conjunction with other systems of the cold shutdown design, to implement the functional requirements of RG 1.139, “Guidance for Residual Heat Removal to Achieve and Maintain Cold Shutdown,” as discussed in Appendix 5A of the BVPS-2 UFSAR. The licensee evaluated a normal cooldown case for BVPS-1 and 2. For BVPS-2, the licensee also evaluated a single-train cooldown case and a natural circulation cooldown case. The normal cooldown case is a normal cooldown, with 2 RHR pumps and 2 RHR heat exchangers in service. One RCP is assumed to be running between 350 EF and 160 EF. The RCS is cooled from 350 EF to 140 EF (refueling), at the maximum allowable cooldown rate of 90 EF/hr. The licensee’s results indicate that the final RCS temperature of 140 EF is reached in 34 hours for BVPS-1 and in 51 hours for BVPS-2.

The single-train cooldown (BVPS-2) is accomplished with one RHR pump feeding one RHR heat exchanger. One RCP is assumed to be running between 350 EF and 200 EF. The RCS is cooled from 350 EF to 200 EF (cold shutdown), at the maximum allowable cooldown rate of 90 EF/hr. For BVPS-2, the final RCS temperature of 200 EF is reached in 57.9 hours. The natural circulation cooldown (BVPS-2) is based upon Appendix 5A of the UFSAR, with an RHRS cut-in at 36 hours. The RCS is cooled slowly, via natural circulation, to a final temperature of 200 EF. AFW and safety grade SG PORVs are used to cool down the plant to RHR cut-in conditions within 36 hours. For BVPS-2, the final RCS temperature of 200 EF is reached in 43 hours.

With respect to 10 CFR Part 50, Appendix R, the total time required to reach cold shutdown conditions, for BVPS-2, remains within the 72-hour acceptance criteria specified in SRP Section 9.5.1. For BVPS-1, the cooldown time without offsite power and the RHR system, remains at 127 hours at EPU conditions, which is consistent with the NRC-approved plant-specific cold shutdown time requirement [25]. Therefore, the NRC staff finds that the RHR systems at BVPS-1 and 2 are capable of supporting the proposed EPU.

Conclusion

The NRC staff has reviewed the licensee’s analyses related to the effects of the proposed EPU on the RHR system. The staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the RHR system will maintain its ability to cool the RCS following shutdown and provide decay heat removal. Based

on this, the staff concludes that the RHR system will continue to meet the requirements of GDCs 4, 5, and 34, as well as SRP Section 5.4.7, following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the RHR system.

2.8.5 Accident and Transient Analyses

2.8.5.1. Increase in Heat Removal by the Secondary System

2.8.5.1.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of an SG Relief or Safety Valve (EPULR Sections 5.3.9 and 5.3.10)

Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) postulated initial core and reactor conditions, (2) methods of thermal and hydraulic analyses, (3) the sequence of events, (4) assumed reactions of reactor system components, (5) functional and operational characteristics of the RPS, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; (3) GDC 20, insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; and (4) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.1.1-4 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Decrease in Feedwater Temperature, Increase in Feedwater Flow

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 CHF not being exceeded, pressure in the RCS and main steam system (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 SRP Section 15.1.1-4.

The licensee used the LOFTRAN computer code to analyze the BVPS-1 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 L-05-112 [10], 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 2300 psia (limit is 2748.5 psia), and the peak secondary pressure was 914 psia (limit is 1208.5 psia). In response N.2 of L-05-112, the licensee provided the analysis results comparing the transient response using the model 51 SGs and the model 54F SGs. The plant responses were almost identical. Figures N.2-1 and N.2-3 of L-05-112 show that the acceptance criteria continue to be met.

The NRC staff reviewed the licensee's analysis and concluded that the licensee's analysis was performed using acceptable analytical models. The staff found that the licensee demonstrated that the RPS and safety systems will continue to assure the CHF will not be exceeded and pressures in the RCS and MSS will be maintained below 110 percent of their respective design pressures. The staff concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed EPU program. Therefore, the staff found the proposed EPU program acceptable with respect to the excessive heat removal due to feedwater system malfunction event.

Increase in Steam Flow and Inadvertent Opening of an SG Relief or Safety Valve

An excessive load increase incident is an ANS Condition II event [40] 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 CHF 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 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 L-05-112. Bounding initial conditions for plant parameters that impact DNBR were determined for BVPS units at EPU conditions consistent with the RTDP. The initial conditions were 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 BVPS 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 the BVPS units at the EPU power level meet the EPU safety analysis DNBR limit. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the excessive load increase incident.

Conclusion

The NRC staff has reviewed the licensee's analyses of the excess heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the events stated.

2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment (EPULR Sections 5.3.12 and 5.3.19)

Regulatory Evaluation

The steam release 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 shutdown margin (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 rod cluster control assembly 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 [40], it is analyzed to meet Condition II acceptance criteria. The acceptance criteria are based on CHF not being exceeded. The NRC staff's

review focused on the core response to the MSLB event. Specific review criteria are found in SRP Section 15.1.5.

Technical Evaluation

Steam System Piping Failures at Hot Zero Power (HZP) (EPULR Section 5.3.12)

The licensee used the LOFTRAN computer code to simulate the NSSS response to the HZP MSLB transient and to provide dynamic core conditions to the VIPRE thermal-hydraulic code [43] and ANC core physics code [46]. 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 and 2 analyses of record.

Section 5.3.12.2 [5] 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 for BVPS-1 and 2, respectively. In response Q.1 [10] to an NRC staff RAI regarding the throat area of the integral flow restrictors, the licensee stated that each of the BVPS-1 RSGs contain a 1.4 ft^2 integral flow restrictor. In addition, the BVPS-1 MSLB event assumed unisolable steam paths following MSIV closure (RAI response Q.7 [10]). Further, the licensee stated that the current BVPS-2 SGs contain a 1.069 ft^2 integral flow restrictor and that the current UFSAR AOR is overly conservative, since it assumes a flow restrictor of 1.4 ft^2.

In response Q.13 [10], 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 reality, not all of the AFW flow would be expected to be fed to the faulted loop only, some would be expected to be fed to the unfaulted loops. The modeling assumptions yield a conservatively greater mass/energy release through the break than may actually occur.

In response Q.15 [10], 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 [10], the licensee stated that the analyses explicitly model the individual components of the instrumentation delays and lead/lag times.

In response Q.17 [10], and response 12 [14], regarding the axially dependent CHF correlations, the licensee described the use of the W-3 correlation with a 0.88 multiplier and a correlation 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 core physics code calculation. Figure Q.17-1 [10] depicts a limiting top skewed hot assembly axial power distribution.

In response Q.19 [10], 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 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 [10]) revealed that for both BVPS-1 and 2, the reactor returned to a subcritical condition prior to SG dry out. During an audit at Westinghouse-Monroeville in November 2005 [13], the NRC staff reviewed the Westinghouse engineering calculations supporting this event. As part of the audit, the staff verified the selection and transfer of transient statepoints between the LOFTRAN and VIPRE codes.

Based upon the input parameters, assumptions, and modeling techniques described in Section 5.3.12.2 of the EPULR, and in responses to RAIs [10]; [14], the NRC staff finds that the post-trip MSLB transient simulation and the identification of the limiting cases are acceptable. The limiting BVPS-1 and 2 post-trip MSLB cases demonstrate that the calculated minimum DNBR remains above the DNB SAL of 1.61 (Table 6.1-3 of the EPULR), ensuring that fuel rod failure does not occur. In response 11 [14], regarding the fuel temperature and fuel clad strain design limits, the licensee stated that both of these fuel rod design criteria have been satisfied for the EPU conditions. This provides reasonable assurance that fuel rod failure would not occur as a result of local power density.

Steam System Piping Failures at Hot Full Power (EPULR Section 5.3.19)

The steam system piping failure accident analysis described in Section 5.3.19 of the EPULR 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 was to address 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 [40]. However, the licensee performed its analyses of this event to the more restrictive ANS Condition II acceptance criteria [40]. The NRC staff's review focused on the core response to the MSLB event.

The current licensing basis for the BVPS units does not include a specific assessment of the pre-trip power excursion portion of the MSLB event. The respective sections of the BVPS-1 and 2 UFSARs 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. These computer models and methods have been previously reviewed and approved by the NRC staff for the MSLB analysis [44]; [47].

Section 5.3.19.2 of the EPULR described the input parameters and assumptions used in the pre-trip MSLB analysis. Table 5.3.19-1 of the EPULR lists the sequence of events of the limiting pre-trip MSLB scenarios for both BVPS-1 and 2. In response W.6 [10], 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 and 0.8 ft^2 for BVPS-2. The limiting break size corresponds to the intersection of the timing of the overpower delta-temperature (OPΔT) and low steamline pressure reactor trip functions.

In response W.1 [10], 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 [10], 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 [10], 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 [10], 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 [13], 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 [14], regarding the LOOP assumptions, 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 and 2 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.

The limiting BVPS-1 and 2 pre-trip MSLB cases demonstrate that the calculated minimum DNBR remains above the DNB SAFDL thus ensuring that fuel rod failure does not occur. In response 10 [14], regarding the fuel temperature and fuel clad strain design limits, the licensee stated that both of these fuel rod design criteria have been satisfied for the EPU conditions, assuring that fuel rod failure did not occur as a result of local power density.

Conclusion

Based upon satisfying the more restrictive Condition II acceptance criteria [40], the NRC staff finds that the results of the BVPS-1 and 2, EPU pre-trip and post-trip MSLB analyses are acceptable. The analyses were conducted, at EPU conditions, considering the model 54F RSGs for BVPS-1 and the model 51 OSGs for BVPS-2.

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 staff concludes that the plant will continue to meet the regulatory requirements at EPU conditions with respect to the steam line break.

2.8.5.2 Decrease in Heat Removal By the Secondary System

2.8.5.2.1 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, and Steam Pressure Regulator Failure (EPULR Section 5.3.6)

Regulatory Evaluation

A number of initiating events may result in unplanned decreases in heat removal by the secondary system. These events result in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transients. The NRC staff's review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.1-5 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

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 [40] applicable to this event are that CHF 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 SRP Section 15.2.1-5.

The licensee analyzed two cases for a complete loss of load from full power at EPU conditions: (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 2900 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 [40] SBLOCA, since the peak water volume remained below the total pressurizer volume, demonstrating water relief from the pressurizer had not 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 and MSS safety valves to maintain pressure below the 110 percent design pressure. The peak primary pressure reached was 2747.3 psia, below the design limit of 2748.5 psia and the peak secondary pressure reached was 1191.6 psia, below the design limit of 1208.5 psia. The peak pressurizer water volume remained below the total pressurizer volume, demonstrating water relief from the pressurizer had not occurred.

The NRC staff reviewed the licensee's analyses of the loss of external electric load and concluded that the licensee's analyses were performed using acceptable analytical models. The staff found the licensee demonstrated the minimum DNBR will remain above the SAL and pressures in the RCS and MSS will remain below 110 percent of their respective design pressure values for the proposed EPU. The staff concluded that the BVPS-1 and 2 loss of external electric load/ turbine trip analyses at EPU conditions show that BVPS-1 and 2 will continue to meet applicable regulatory requirements following implementation of the EPU. Therefore, the staff found the proposed EPU program acceptable with respect to the loss of external electrical load event.

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the events stated.

2.8.5.2.2 Loss of Nonemergency AC Power to the Station Auxiliaries (EPULR Section 5.3.8)

Regulatory Evaluation

The loss of nonemergency AC power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant circulation pumps. This causes a flow coastdown as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the reactor coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated

auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.6 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The loss of non-emergency AC power, an ANS Condition II event [40], 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 [40] are based on the CHF 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 SRP Section 15.2.6.

The licensee used the LOFTRAN computer code to analyze this event, consistent with the AOR, 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 SAL. However, the RCS flow coastdown was the initiating fault in the complete loss of flow event, with the reactor trip occurring after the flow has already been degraded. In the loss of non-emergency AC power event, the flow coastdown occurred after the reactor trip.

The NRC staff reviewed the licensee's analysis of the LOAC power to plant auxiliaries and concluded that the licensee's analysis was performed using acceptable analytical models. The staff concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed EPU. Therefore, the staff found the proposed EPU acceptable with respect to the LOAC power to the plant auxiliaries.

Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of non-emergency AC power to station auxiliaries event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the

reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the loss of non-emergency AC power to station auxiliaries event.

2.8.5.2.3 Loss of Normal Feedwater (LONF) Flow (EPULR Section 5.3.7)

Regulatory Evaluation

A LONF flow could occur from pump failures, valve malfunctions, or a LOOP. Loss of feedwater flow results in an increase in reactor coolant temperature and pressure that eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a LONF flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.7 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

An LONF, an ANS Condition II event [40], 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 a 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 RPS provides the protection against a LONF event via a reactor trip on SG low-low water level in one or more SGs. The AFW system starts automatically on SG low-low water level, following a SI signal, on 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 CHF not being exceeded and pressure in the RCS and MSS not exceeding 110 percent of design pressure. Specific review criteria are found in SRP Section 15.2.7.

The LONF transient was analyzed using the LOFTRAN computer code, consistent with the AOR, at EPU conditions. An RCP heat of 15 MWt was assumed in the analysis to account for the heat released by the pumps. Reactor trip occurring on SG low-low water level was

assumed to be set at 5 percent of narrow range span (NRS) for BVPS-1 and zero percent of NRS for BVPS-2. A conservative core residual heat generation was assumed based on the ANS 5.1-1979 Decay Heat model [48], +2 sigma for uncertainties. The licensee analyzed the SG tube plugging levels 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 pressurizer 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 loss of load (LOL) transient [10]. 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. Based on these results, the AFW system capacity is sufficient to dissipate core residual heat, stored energy, and RCP heat such that reactor coolant water would not be discharged through the pressurizer relief or safety valves.

The NRC staff reviewed the licensee's analysis for the LONF transient and concluded the analysis was performed using acceptable analytical models. The staff concluded the licensee's analysis at the EPU conditions bound current licensed power operation of BVPS-1 and 2. Therefore, the staff finds the proposed EPU acceptable with respect to the LONF event.

Conclusion

The NRC staff has reviewed the licensee's analyses of the LONF flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of the LONF flow. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the LONF flow event.

2.8.5.2.4 Feedwater System Pipe Breaks Inside and Outside Containment (EPULR Section 5.3.17)

Regulatory Evaluation

A major feedwater line break (FLB), an ANS Condition IV event [40], 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 energy discharge through the break) or an RCS heatup (by reducing feedwater flow to the affected RCS loop). In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) postulated initial core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) the assumed response of the reactor coolant and auxiliary systems, (5) the functional and operational characteristics of the reactor protection system, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; (3) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (4) GDC 35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling. Specific review criteria are contained in SRP Section 15.2.8 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Cases that can cause an RCS cooldown were covered by the analysis of the steamline break event, also an ANS Condition IV event [40]. Therefore, an FLB 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.

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 and 2 UFSAR FLB analyses. Section 5.3.17.2 of the EPULR describes the inputs and assumptions used in the analyses. Tables 5.3.17-1A and 5.3.17-1B of the EPULR list the sequence of events of the limiting FLB scenarios for BVPS-1 and 2, respectively.

In response U.2 [10], and response 2 [14] 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 [45], the largest possible break size may not yield the most conservative results. However, the break spectrum analysis

demonstrated that BVPS-1 and 2 continued to satisfy the acceptance criteria for all possible break sizes. 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 [14]. The FLB methodology, including the interaction between NOTRUMP and LOFTRAN, was consistent with the current UFSAR analyses. In response 1 [14], regarding a discrepancy with the UFSAR methodology description, the licensee stated that there have been no methodology changes and that the BVPS-1 and 2 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, the NRC staff finds this acceptable.

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 [14], 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-percent 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 percent. It is expected that the modeling uncertainty of NOTRUMP's ability to predict indicated liquid level will be well within this value. Based on these conservative modeling techniques, the staff finds that the credited actuations on indicated SG downcomer liquid level are acceptable.

In response 4 [14], 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 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 [14]). The results of this sensitivity study demonstrated that BVPS-1 and 2 maintain margin to hot leg saturation even when a saturated liquid discharge was assumed. Therefore, the staff finds that this issue does not need to be specifically addressed to support the EPU application. The Westinghouse CAP issue report previously identified will investigate these issues on a generic basis.

In response U.3 [10], and response 2 [14], regarding the mitigating actions of the 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 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 staff noted that these events were design-basis events for primary and secondary safety valve relief capacity. Whereas, the RCS cooldown and subsequent heatup (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 staff independently ran the limiting FLB LOFTRAN cases (during the audit at the Monroeville offices of Westinghouse). As expected, the calculated peak RCS pressures were higher, without operation of the PORVs; but still within 110 percent of design pressure. 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 percent of design. Therefore, the staff finds this acceptable.

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 [14], regarding PORV operation and pressurizer fill, the licensee stated that the FLB analysis at EPU conditions had demonstrated that no water relief occurs. The staff's independent LOFTRAN cases confirm that with no credit for PORV operation, pressurizer liquid level remained below the PSV elevation. The 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 SI) to control pressurizer water level in accordance with plant procedures. The staff finds this acceptable.

In response U.1 [10], regarding the effect of a harsh environment on the plant's instrumentation response, the licensee provided a discussion of the qualification of the credited instrumentation and of the determination of setpoints for the analyses. The licensee includes cable and instrument degradation allowances in the instrument bias for determining setpoints. The NRC staff finds the licensee's response describes an acceptable approach to dealing with a harsh environment.

Based upon the input parameters, assumptions, and modeling techniques described in Section 5.3.17.2 of the EPULR, and in responses to RAIs [10]; [14], the NRC staff finds the BVPS-1 and 2 FLB transient simulations and the identification of the limiting cases acceptable. The licensee, as demonstrated by independent staff calculations, provided reasonable assurance that all of the acceptance criteria continue to be met. The BVPS-1 and 2 AFW system capacities were adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core. Based upon satisfying these acceptance criteria, the staff finds that the results of the BVPS-1 and 2 FLB analysis are acceptable. The Model 54F RSGs were analyzed for BVPS-1 and the OSGs were analyzed for BVPS-2 at EPU conditions.

The NRC staff reviewed the FLB analyses and concludes that the licensee's analyses adequately account for operation of the plants at EPU conditions and were performed using

acceptable analytical models. The 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. The staff also concludes that the plant will continue to meet the regulatory requirements at EPU conditions with respect to the FLB events.

Conclusion

The NRC staff reviewed the FLB analyses and concluded that (1) they were performed using acceptable analytical models, and (2) they adequately account for operation of the plant at the proposed EPU conditions. The staff further concluded that the licensee demonstrated that the reactor protection and safety systems will continue to assure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, and adequate core cooling will be provided. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, 31, and 35 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to feedwater system pipe breaks.

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Partial and Complete Loss of Forced Reactor Coolant Flow (EPULR Sections 5.3.13 and 5.3.14)

Regulatory Evaluation

A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer. An increase in fuel temperature and accompanying fuel damage could then result if SAFDLs are exceeded during the transient. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the postulated initial core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) assumed reactions of reactor systems components, (5) the functional and operational characteristics of the reactor protection system, (6) operator actions, and (7) the results of the transient analyses. The NRC’s acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Sections 15.3.1 and 15.3.2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Partial Loss of Coolant Flow (EPULR Section 5.3.13)

A partial loss of coolant flow, an ANS Condition II event [40], 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 overcurrent 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 CHF not being exceeded and that the peak RCS and MSS pressures remain below 110 percent of their respective design pressures. Specific review criteria are found in SRP Sections 15.3.1 and 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 were 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, both greater than the SAL values of 1.55 and 1.33, respectively. 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 continued to be met.

The NRC staff reviewed the licensee's analysis results and concluded that the licensee's analysis was performed using acceptable analytical models and the analysis was bounding for current licensed power operation under EPU conditions. The staff concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed EPU. Therefore, the staff found the proposed EPU acceptable with respect to the partial loss of forced reactor coolant flow event.

Complete Loss of Coolant Flow (EPULR Section 5.3.14)

A complete loss of forced reactor coolant flow, an ANS Condition III event [40], 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 SAFDLs are exceeded during the transient. The RPS and safety systems are actuated to mitigate the transient. The ANS Condition II acceptance criteria [40] were conservatively applied to the analysis of this event. The CHF must not be exceeded, and pressure in the RCS and MSS must stay below 110 percent of their respective design pressures. Specific review criteria are found in SRP Sections 15.3.1 and 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 and secondary systems pressure and temperature transients. 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 SAL values of 1.33/1.55 respectively. The peak RCS and MSS pressures (2504.1 psia for RCS (BVPS-1) and 1002.7 psia for MSS (BVPS-2)) remained below their respective limits (2748.5 psia and 1208.5 psia) at all times.

The NRC staff reviewed the licensee's analyses of the complete loss of reactor coolant flow and concluded the licensee's analyses were performed using acceptable analytical models. The staff found that the licensee demonstrated that the RPS and safety systems will continue to ensure the minimum DNBR will remain above the SAL and pressure in the RCS and MSS will be maintained below 110 percent of the design pressures. Therefore, the staff finds the proposed EPU acceptable with respect to the complete loss of reactor coolant flow.

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in reactor coolant flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the decrease in reactor coolant flow event.

2.8.5.3.2 Reactor Coolant Pump (RCP) Rotor Seizure and RCP Shaft Break (EPULR Section 5.3.15)

Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of an RCP. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer, which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the postulated initial and long-term core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) the assumed reactions of reactor system components, (5) the functional and operational characteristics of the RPS, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 27, insofar as it

requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core; and (3) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Sections 15.3.3 and 15.3.4 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The locked rotor accident, an ANS Condition IV event [40], can result from an instantaneous seizure of the RCP rotor or the break of the RCP shaft.

The ANS Condition IV event acceptance criteria [40] 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 SRP Sections 15.3.3 and 15.3.4.

The licensee used the LOFTRAN, FACTRAN, and VIPRE computer codes to analyze this event 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 peak cladding temperature. The results of the analyses showed that the peak RCS pressure was 2797 psia, less than the acceptance criterion of 2997 psia. The peak cladding temperature 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 cases), which is less than the total percentage of fuel rods in DNB that is assumed in the radiological dose evaluation. The NRC staff's review of this analysis focused on the assumptions used in LOFTRAN to calculate the bulk pressure and temperature transients, and on the transfer of this information to VIPRE for the DNB evaluation. In RAI response S.3 of L-05-112 [10], the licensee provided supplemental information on how the percent of rods in DNB

were calculated. The analysis verified that the predicted percent of rods in DNB, that is used for dose evaluation, was within the assumed value.

The NRC staff reviewed the licensee's analyses of the locked rotor and pump shaft break events and concluded the licensee's analyses were performed using acceptable analytical models. The staff concluded the plant will continue to meet the regulatory requirements following implementation of the proposed EPU. Therefore, the staff found the proposed EPU acceptable with respect to the RCP locked rotor and shaft break accidents.

Conclusion

The NRC staff has reviewed the licensee's analyses of the sudden decrease in core coolant flow events and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and adequate core cooling will be provided. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, and 31 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the sudden decrease in core coolant flow events.

2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition (EPULR Section 5.3.2)

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal from subcritical or low power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered (1) the description of the causes of the transient and the transient itself, (2) the initial conditions, (3) the values of reactor parameters used in the analysis, (4) the analytical methods and computer codes used, and (5) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.1 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The uncontrolled RCCA withdrawal from subcritical or low power startup condition is an ANS Condition II [40] 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 rated thermal power level or secondary-side conditions. Nevertheless, the licensee re-analyzed this event for BVPS-1 and 2 at the 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 SAL value, and peak fuel clad temperature is not exceeded at the NSSS power of 2910 MWt.

The NRC staff reviewed the licensee’s analysis of the uncontrolled RCCA withdrawal from a subcritical condition and concluded that the licensee’s analysis was performed using acceptable analytical models. The staff also concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the uncontrolled RCCA withdrawal from a subcritical condition event.

Conclusion

The NRC staff has reviewed the licensee’s analyses of the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition and concludes that the licensee’s analyses have adequately accounted for the changes in core design necessary for operation of the plant at the proposed power level. The staff also concludes that the licensee’s analyses were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition.

2.8.5.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power (EPULR Section 5.3.3)

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal at power may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered (1) the description of the causes of the AOO and the description of the event itself, (2) the initial conditions, (3) the values of reactor parameters used in the analysis, (4) the analytical methods and computer codes used, and (5) the results of the associated analyses. The NRC’s acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Unlike the uncontrolled RCCA withdrawal from subcritical or low power startup condition, the uncontrolled RCCA withdrawal at power, also an ANS Condition II event [40], is affected by RTP, and the secondary system design, 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 MSS pressure boundary. The acceptance criteria are based on not exceeding CHF and that pressures in the RCS and MSS be maintained below 110 percent of the design pressures. Specific review criteria are found in 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 high neutron flux and OTΔT trip signals. A series of 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. For the slower reactivity insertion rates, the OTΔT trip signal was generated before the power-range high neutron flux trip signal. For the faster reactivity insertion rates, the power-range high neutron flux trip signal occurred first. Both cases analyzed show the minimum DNBR was greater than the SAL value of 1.55. The analysis results indicated that the minimum DNBR, 1.57, occurs during the case that is analyzed at 100 percent initial power with minimum reactivity feedback and a constant reactivity insertion rate.

In response to an NRC staff RAI regarding overpressurization, the licensee stated in RAI response H.3 of L-05-112 [10] and RAI response 7 of L-05-165 [14], 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 in conjunction with the positive rate flux trip reactor trip function to prevent overpressurization for this event. A 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-1 and 2 EPU.

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 staff also concluded that the plant will continue to meet the regulatory requirements in the AOR following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the uncontrolled RCCA withdrawal at power event.

Conclusion

The NRC staff has reviewed the licensee’s analyses of the uncontrolled control rod assembly withdrawal at power event and concludes that the licensee’s analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The staff also concludes that the licensee’s analyses were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal at power.

2.8.5.4.3 Control Rod Misoperation (EPULR Section 5.3.4)

Regulatory Evaluation

The NRC staff's review covered the types of control rod misoperations that are assumed to occur, including those caused by a system malfunction or operator error. The review covered (1) descriptions of rod position, flux, pressure, and temperature indication systems, and those actions initiated by these systems (e.g., turbine runback, rod withdrawal prohibit, rod block) which can mitigate the effects or prevent the occurrence of various misoperations; (2) the sequence of events; (3) the analytical model used for analyses; (4) important inputs to the calculations; and (5) the results of the analyses. The NRC’s acceptance criteria are based on (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to initiate automatically operation of systems and components important to safety under accident conditions; and (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.3 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The RCCA misoperation events are ANS Condition II events [40] 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 [41]. The generic dropped RCCA statepoints are evaluated in each cycle as part of the reload safety evaluation process in order to demonstrate that the applicable DNB design basis is satisfied. In RAI response I.1 of L-05-112 [10], the licensee provided an explanation on how the generic statepoints are applicable and remain valid to the BVPS-1 and 2 EPU. Use of this NRC-accepted, dropped rod methodology [41], has shown that the DNBR SAL is not exceeded and the acceptance criteria continue to be met.

The NRC staff agrees with the approach for the RCCA misoperation events using the NRC-accepted, dropped rod methodology in the context of the BVPS-1 and 2 EPU. Because the DNBR SAL is not exceeded and the acceptance criteria continue to be met, the staff finds the RCCA misalignment evaluation acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of control rod misoperation events and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The staff also concludes that the licensee's analyses were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs will not be exceeded during normal or anticipate operational transients. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to control rod misoperation events.

2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature (EPULR Section 5.3.1)

Regulatory Evaluation

A startup of an inactive loop transient may result in either an increased core flow or the introduction of cooler or deborated water into the core. This event causes an increase in core reactivity due to decreased moderator temperature or moderator boron concentration. The NRC staff's review covered (1) the sequence of events, (2) the analytical model, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC 20, insofar as it requires that the protection system be designed to automatically initiate the operation of appropriate systems to ensure that SAFDLs are not exceeded as a result of operational occurrences; (3) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during AOOs; (4) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core; and (5) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs,

SAFDLs are not exceeded. Specific review criteria are contained in SRP Sections 15.4.4 and 15.4.5 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

BVPS-1 and 2 are equipped with reactor coolant loop isolation valves. The TSs prohibit power operation with any of the reactor coolant loop isolation valves closed. The TSs also prohibit

power operation with less than all 3 RCPs in operation. This event is not analyzed, since the plant is not permitted to operate in a configuration at which the event is postulated to occur.

Conclusion

The NRC staff finds the proposed EPU acceptable with respect to the inactive loop startup event. The staff agrees with the licensee, that this event could not occur as long as the plant is operated within TS requirements.

2.8.5.4.5 Chemical and Volume Control System (CVCS) Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant (EPULR Section 5.3.5)

Regulatory Evaluation

Unborated water can be added to the RCS, via the CVCS. This may happen inadvertently because of operator error or CVCS malfunction, and cause an unwanted increase in reactivity and a decrease in shutdown margin. The operator should stop this unplanned dilution before the shutdown margin is eliminated. The NRC staff's review covered (1) conditions at the time of the unplanned dilution, (2) causes, (3) initiating events, (4) the sequence of events, (5) the analytical model used for analyses, (6) the values of parameters used in the analytical model, and (7) results of the analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; (2) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.4.6 and other guidance is provided in Matrix 8 of RS-001.

SRP Section 15.4.6 stipulates that boron dilution events be considered for all modes of operation. Typically, the way licensees show acceptable results for this transient is to demonstrate the operators have sufficient time to terminate the boron dilution before a complete loss of SDM. If SDM is not lost then the reactor does not return to criticality and boron dilution is bounded by other analysis. This is the means by which the BVPS-1 and 2 licensee has chosen to demonstrate acceptable results. The SRP acceptance criteria are that the operators have at least 15 minutes from notification of the onset of a boron dilution event until a complete loss of SDM for Modes 1, 2, 3, 4, and 5, and at least 30 minutes in Mode 6. Wording in the licensee's UFSAR [3] and EPULR would indicate this SRP acceptance criteria applied to BVPS-1 and 2. However, the licensee's UFSAR and initial EPULR did not contain analyses to support this expectation and acceptance criteria. Specifically, the 15-minute acceptance criterion to terminate the event appeared to be based on initiation of the event rather than operator notification, and there was no analysis for Modes 4, 5, and 6. The EPULR stated a boron dilution event could not occur during Modes 4, 5, and 6. This is supported by BVPS-1 and 2 TSs, which require the boron dilution source valves to be verified closed within 15 minutes of the completion of a boron dilution in Modes 4, 5, and 6. When queried for confirmation of their actual licensing basis, the licensee affirmed that the licensing basis for

BVPS-1 is RG 1.70, Revision 0, and that the licensing basis for BVPS-2 is RG 1.70, Revision 3 [17]. This means the boron dilution acceptance criteria is different for BVPS-1 and 2. For BVPS-1 the acceptance criterion is 15 minutes to terminate from event initiation. For BVPS-2 the acceptance criterion is 15 minutes to terminate from operator notification.

Technical Evaluation

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 [40] that requires that the CHF 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 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 L-05-112 [10].

Boron Dilution Parameters

	Initial Boron Concentration (ppm)		Critical Boron Concentration (ppm)		Dilution Flow (gpm)		Dilution Volume (ft3)	
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2
Mode 1	*1800*	*1800*	1500	1500	231	231	7593	7520
Mode 2	*1800*	*1800*	1500	1500	231	231	7593	7520
Mode 3	*2079*	*2079*	1900	1900	231	231	6964	6893

The licensee's analysis of this event included the effect of the BVPS-1 RSGs on the dilution volume. Otherwise, the key parameters are the same for both units.

The following table shows the BVPS-1 and 2 EPU results for the boron dilution event.

Boron Dilution Results

Condition	**Unit 1**	**Unit 2**	**Limit**

Mode 1 Manual Rod Control	30.4 Minutes	29.4 Minutes	15 Minutes
Mode 1 Auto Rod Control	31.7 Minutes	31.4 Minutes	15 Minutes
Mode 2	33.3 Minutes	33.0 Minutes	15 Minutes
Mode 3	15.3 Minutes	15.0 Minutes	15 Minutes

An audit was conducted of the analysis that supports the licensee's EPU LAR. That audit is the source of the initial boron concentration numbers. That audit also confirmed that the flow rates and dilution volumes are appropriately conservative. That audit also confirmed that for both BVPS-1 and 2, the analysis explicitly accounts for operator notification for Mode 1 manual rod control, and implicitly accounts for operator notification for Mode 1 automatic rod control and Mode 2. The audit confirmed that the analysis makes no accommodation for operator notification for Mode 3.

As can be seen from the above table, the licensee has sufficient margin for its Mode 1 and 2 analyses. For its BVPS-1 Mode 3 analysis, the licensee must show the operator has at least 15 minutes from initiation of the boron dilution event until all SDM is lost. As the licensee has demonstrated there are 15.3 minutes for operator action, this analysis is acceptable. However, the licensee's BVPS-2 Mode 3 analysis must show the operator has at least 15 minutes from operator notification of the boron dilution event until all SDM is lost. What the licensee has shown is that the operator has at least 15 minutes from initiation of the boron dilution event until all SDM is lost. Hence, the time from initiation until the operator is notified of the event must be subtracted from the licensee's BVPS-2 Mode 3 results. The licensee has affirmed that the operator will be notified 'almost immediately' [17] upon initiation of a boron dilution event in Mode 3. Additionally, the licensee has validated operator response times for various transients [56]. In Table 2-2 [56], the licensee has affirmed that the operator will terminate a boron dilution event within 1 minute of its initiation, for Modes 1, 2, and 3. Therefore, as the licensee has affirmed the lag time from event initiation and operator notification will be minimal and that the operator's response time is much less than the 15-minute acceptance criterion, the NRC staff concludes there is reasonable assurance that there will not be total loss of SDM for a BVPS-2 boron dilution event and the current analysis is acceptable. The licensee did initiate an internal corrective action tracking item to capture the need to account for the operator notification time (15 minutes) the next time it updates the BVPS-2 boron dilution calculation.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's analyses of the decrease in boron concentration in the reactor coolant due to a CVCS malfunction and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the decrease in boron concentration in the reactor coolant due to a CVCS malfunction.

2.8.5.4.6 Spectrum of Rod Ejection Accidents (EPULR Section 5.3.16)

Regulatory Evaluation

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 NRC staff evaluates the consequences of a control rod ejection accident to determine the potential damage caused to the RCPB and to determine whether the fuel damage resulting from such an accident could impair cooling water flow. The staff's review covered initial conditions, rod patterns and worths, scram worth as a function of time, reactivity coefficients, the analytical model used for analyses, core parameters which affect the peak reactor pressure or the probability of fuel rod failure, and the results of the transient analyses. The NRC's acceptance criteria are based on GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to impair significantly the capability to cool the core. Specific review criteria are contained in SRP Section 15.4.8 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

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. Since the key acceptance criterion is maximum fuel stored energy, initial plant conditions are selected to maximize fuel stored energy. This event is considered at 0-percent and 100-percent power, and at beginning of life (BOL) and EOL. Since the RCCA ejection transient is a rapid transient, initial plant conditions, such as power level, pressure, flow, and temperature are not significant.

The control rod ejection accident analyses for BVPS-1 and 2 were performed assuming the EPU power level, at BOL and EOL. The full-power cases indicated that 6.63 percent and 5.98 percent of the fuel would melt (BOL and EOL). The corresponding maximum fuel stored energy was 181.6 and 174.7 cal/g. For the zero power cases, there was no fuel melt, and the maximum fuel stored energy was 103.4 and 169.8 cal/g (BOL and EOL).

As a result of a fuel failure during a test at the CABRI reactor in France in 1993, and one at the NSRR test reactor in Japan in 1994, the NRC recognized that high burnup fuel cladding might fail during a reactivity insertion accident (RIA), such as a rod ejection event, at lower enthalpies than the limits currently specified in RG 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors." However, generic analyses performed by all of the reactor vendors have indicated that the fuel enthalpy during RIAs will be much lower than the RG 1.77 limits, based on their 3D neutronics calculations. For high burnup fuel which has been burned so long that it no longer contains significant reactivity, the fuel enthalpies calculated using the 3D models are expected to be much lower than 100 cal/g.

The NRC staff has concluded that although the RG 1.77 limits may not be conservative for cladding failure, the analyses performed by the vendors, which have been confirmed by NRC-sponsored calculations, provide reasonable assurance that the effects of postulated RIAs in operating plants with fuel burnups up to 60 gigawatt days per metric ton uranium will neither (1) result in damage to the RCPB, nor (2) sufficiently disturb the core, its support structures, or other RPV internals to impair significantly the capability to cool the core as specified in current regulatory requirements.

A generic calculation of the pressure surge for an ejected rod worth of one dollar at BOL, HFP, indicated that the peak pressure would not exceed faulted condition stress limits for the RPV [58]. The BVPS-1 and 2 EPU analyses continue to be bounded by this analysis. Since fuel and clad limits are not exceeded, there is no danger of sudden fuel dispersal into the coolant, and since the peak pressure does not exceed the faulted condition stress limits, there is no danger of additional damage to the RCS. The analyses demonstrate that the fission product release as a result of fuel rods entering DNB is limited to less than 10 percent of the fuel rods in the core.

The NRC staff finds that the results and conclusions of the analyses performed for the control rod ejection accident are acceptable for operation at the proposed EPU power level of 2900 MWt at BVPS-1 and 2. The dose analysis was previously reviewed and approved by the staff in License Amendment Nos. 257 and 139 [57].

Conclusion

The NRC staff has reviewed the licensee's analyses of the rod ejection accident and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could (1) result in damage to the RCPB greater than limited local yielding, or (2) cause sufficient damage that would significantly impair the capability to cool the core. Based on this, the staff concludes that the plant will continue to meet the requirements of GDC 28 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the rod ejection accident.

2.8.5.5 Inadvertent Operation of ECCS and CVCS Malfunction that Increases Reactor Coolant Inventory (EPULR Section 5.3.18)

Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the boron concentration and temperature of the injected water and the response of the automatic control systems, a power level increase may result and, without adequate controls, could lead to fuel damage or overpressurization of the RCS. Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during AOOs; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Sections 15.5.1 and 15.5.2 and other guidance is provided in Matrix 8 of RS-001 and RIS-2005-29 [49].

Technical Evaluation

An inadvertent actuation of the ECCS at-power event, an ANS Condition II event [40], could be caused by operator error or a false electrical actuating signal. Actuation of the ECCS starts the charging pumps that pump borated water from the refueling water storage tank (RWST) into the cold leg of each RCS loop. The SI pumps also start automatically but provide no flow when the RCS is at normal pressure.

The inadvertent ECCS actuation at-power event adds water to the RCS until the ECCS is shut off by the operator. This event could develop into a more serious event, an ANS Condition III small break LOCA [40], if the pressurizer fills and a pressurizer relief or safety valve opens and fails to reseat [49]. This would be a violation of the ANS Condition II acceptance criterion [40] that prohibits escalation of a Condition II event to a more serious event (e.g., SBLOCA).

A simple way to show that this ANS Condition II acceptance criterion is met, is to show that there is enough time for the operator to shut off SI before the pressurizer can become water-solid. The licensee's BVPS-1 and 2 inadvertent ECCS actuation analyses, however, indicate that the pressurizer would fill, and would cause water to be discharged through either the PORVs or the PSVs. Therefore, the licensee performed a PSV operability assessment to determine whether the PSVs would remain operable, under water relief conditions, until the operator can terminate SI. Water-qualified PSVs could then be credited to mitigate the event, without assuming the operation of any PORVs. In practice, however, the licensee assumes appropriate operator actions are taken to assure that at least one pressurizer PORV is available for pressure relief.

The licensee's analyses are based upon two assumptions:

(1) The PORVs, PSVs, and their associated discharge piping are qualified for water relief.
(2) The automatic control system circuitry for the PORVs is qualified to Class 1E standards, such that it can be relied upon to supply a closing signal when required.

Although the PORVs are not credited to mitigate the event in the licensee's analyses, it must be recognized that the maximum SI flow could cause the pressurizer to become water-solid and the PORVs to open and discharge water. Therefore, they must be shown to close when the RCS depressurizes below their closing setpoints. This requires the PORVs to be qualified for water relief, and their automatic control system circuitry to supply a valid closing signal.

Qualification for water relief

The licensee's analyses, which do not credit operation of the PORVs, show the cycling of the PSVs, and also provide a transient history of the temperature of the water that is discharged through the PSVs. Thus, it is possible to verify that the discharged water does not become cold enough to invalidate the PSV water qualification bases.

The licensee's PSV operability assessments [17] compared the safety valve fluid relief conditions from the safety analyses to the EPRI safety valve test results for the Target Rock safety valves for BVPS-1 [52], and to the EPRI safety valve test results for the Crosby safety valves for BVPS-2 [53]. The PSV operability assessments used a feedline break methodology

[54] that was extended to address the inadvertent actuation of the ECCS at power event. This methodology has not been accepted by the NRC staff. The staff considered the licensee's methodology as an alternate approach for assessing PSV operability, as it conducted its own, independent evaluation.

The object of these PSV operability assessments is to show that the valves will operate in a stable manner when subjected to the relief conditions (i.e., flow rates, pressures, and temperatures) and to the number of lift cycles that are predicted by analyses of the inadvertent ECCS actuation at-power event for the time during which PSV fluid relief occurs until the time it is ended by operator action, about 10 minutes after the event's initiation. Based on these PSV operability assessments, the licensee concluded that the BVPS-1 and 2 PSVs will exhibit stable operation, will function properly, and will reseat properly during and after an inadvertent ECCS actuation at power event at BVPS-1 and 2. Based on its independent evaluation, the NRC staff's conclusions are similar.

For BVPS-1, the temperature of the discharged water is well above the minimum temperature required to qualify its PSVs (which are manufactured by Target Rock) for water relief. The licensee provided plots of the pressurizer water temperatures, from analyses of the inadvertent ECCS actuation at power event that indicate the minimum temperature of the discharged liquid for both BVPS-1 and 2 would be approximately 620 EF. To evaluate the capability of the valves to discharge and reseat, the NRC staff reviewed the available data from the full flow tests performed during the EPRI test program, for the specific PSV models representative of those installed at BVPS-1 and 2. The licensee also considered the methodology contained in topical report WCAP-11677 [54], and determined that the minimum acceptable liquid temperature for which the PSVs are expected to successfully discharge and reseat is less than the minimum expected temperature for the inadvertent actuation of the ECCS at power event for both BVPS1 and 2. The results of the staff's evaluation indicate that both the minimum expected liquid discharge temperature and the minimum acceptable liquid temperature have been conservatively calculated. Therefore, the staff has determined that for purposes of preventing the occurrence of a more serious condition III event there is reasonable assurance that the PSVs would adequately discharge and reseat following an inadvertent actuation of the ECCS at power event.

The PORV valve design will accommodate either steam or water discharge. The PORVs and the associated discharge piping for the safety and relief valves have been analyzed for solid water flow, including the valve inlet loop seal water slugs, during an inadvertent actuation of the ECCS at EPU power event [10]. The NRC staff agrees that the PORVs and the associated discharge piping for the safety and relief valves are qualified for service under the water discharge conditions that would be characteristic of an inadvertent actuation of the ECCS at EPU power event.

Automatic control system circuitry

The control circuitry for the PORVs is considered control grade and does not meet Class 1E requirements. Automatic opening of the PORVs is not credited in any safety analysis unless operation of these valves aggravates the analysis results.

Since BVPS-1 and 2 will rely upon water discharge through the pressurizer PSVs to mitigate the inadvertent actuation of the ECCS at power event, operation of the PORVs is not necessary,

and not credited in the safety analyses. However, the pressurizer PORVs probably will open, during an inadvertent actuation of the ECCS at power event, and if the pressurizer is water-solid, will discharge water. Therefore, the PORVs must be shown to reseat properly, after having discharged water. This requires that the automatic control circuitry that controls the closing of the pressurizer PORVs meets Class 1E requirements [10], as well as qualification of the PORVs and associated discharge piping for water relief.

The pressurizer PORVs close automatically when power to the solenoid is lost, when instrument air is lost, or when the high pressure signal to open the valve is re-set. The pressurizer PORVs receive a Class 1E automatic close signal during low RCS pressure conditions (below the P-11 setpoint). The P-11 permissive allows the manual blocking of SI actuation on a low pressurizer pressure signal, and blocks automatic opening of the PORVs (see sheet 11 of Figure 7.2-1 [3]). Thus, the PORVs at both units receive a Class 1E automatic close signal on a lower than normal RCS operating pressure (P-11), as detected by 2 of 3 safety-related pressure channels. The PORVs at both units are designed to fail closed. This means that the PORVs could remain open until the P-11 setpoint is reached, which creates, in effect, a short-lived RCS depressurization event. This is another Condition II event [40], addressed in LAR Section 5.3.11. In this instance, the RCS depressurization is automatically ended when the PORVs are closed, and there is no DNB concern, since the reactor is already tripped.

The NRC staff agrees that the PORVs can be relied upon to automatically close when pressurizer pressure drops below the closing setpoint because the installed plant equipment used for automatic closure of each PORV meets Class 1E requirements. The licensee's analyses, supported by PSV operability assessments [17], qualification of the PORV and PSV discharge piping, and the availability of a Class 1E closing signal from the PORV automatic control system circuitry, confirm that the inadvertent actuation of the ECCS at power event, an ANS Condition II event, would not develop into an SBLOCA, due to a stuck open PORV or PSV.

Like the inadvertent actuation of the ECCS at power event, the CVCS malfunction that increases reactor coolant inventory can fill the pressurizer and result in water discharge from the pressurizer. The time to fill the pressurizer is longer, due to less charging flow and the reactor trip. Otherwise, the concerns and mitigation requirements for this event are the same as for the inadvertent actuation of the ECCS at power event. The NRC staff finds that the CVCS malfunction that increases reactor coolant inventory is bounded by the inadvertent actuation of the ECCS event, and has been adequately addressed by the licensee.

Conclusion

The NRC staff reviewed the licensee's analyses of the inadvertent ECCS actuation at power event and concluded that the licensee's analyses were performed using previously approved analytical models with the exception of the water qualification of PSVs, where the staff performed its own independent analysis and achieved results similar to the licensee's. The staff finds that the licensee's water qualification model of the PSVs is acceptable. The staff also concluded that the plant will continue to meet GDCs 10, 15, and 26 and the SRP acceptance criteria following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the inadvertent ECCS actuation at power event.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of Pressurizer Pressure Relief Valve (EPULR Section 5.3.11)

Regulatory Evaluation

The inadvertent opening of a pressure relief valve results in a reactor coolant inventory decrease and a decrease in RCS pressure. A reactor trip normally occurs due to low RCS pressure. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.6.1 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

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 [40]. The key acceptance criterion requires that DNBR does not go below the SAL at any time during the transient. Specific review criteria are found in 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 of L-05-165 [14], 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 assure 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 pressurizer safety valve event and concluded that the licensee's analyses were performed using acceptable analytical models. The staff concluded that the licensee demonstrated the RPS and safety systems will continue to provide reasonable assurance that the DNB SAL will not be violated. Since this is a depressurization event, the RCS pressure limits are not challenged. The staff

concluded that the plant will continue to meet the applicable GDCs and the SRP acceptance criteria following implementation of the proposed EPU. Therefore, the staff found the proposed EPU acceptable with respect to the accidental depressurization of the RCS event.

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent opening of a pressurizer pressure relief valve event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the inadvertent opening of a pressurizer pressure relief valve event.

2.8.5.6.2 Steam Generator Tube Rupture (EPULR Section 5.4)

Regulatory Evaluation

An SG tube rupture (SGTR) event causes a direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and main steam safety or atmospheric relief valves. Reactor protection and ESFs are actuated to mitigate the accident and restrict the offsite dose to within the guidelines of 10 CFR Part 100. The NRC staff's review covered (1) postulated initial core and plant conditions, (2) method of thermal and hydraulic analysis, (3) the sequence of events (assuming offsite power either available or unavailable), (4) assumed reactions of reactor system components, (5) functional and operational characteristics of the RPS, (6) operator actions consistent with the plant's emergency operating procedures (EOPs), and (7) the results of the accident analysis. A single failure of a mitigating system is assumed for this event. The staff's review of the SGTR is focused on the thermal and hydraulic analysis for the SGTR in order to (1) determine whether 10 CFR Part 100 is satisfied with respect to radiological consequences, which are discussed in Section 2.7 of this SE, and (2) confirm that the faulted SG does not experience an overfill. Preventing SG overfill is necessary in order to prevent the failure of main steam lines. Specific review criteria are contained in SRP Section 15.6.3 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The SGTR accident, an ANS Condition IV event [40], 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 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 SRP Section 15.6.3. This review is limited to the thermal hydraulics modeling of the analysis. The radiological dose consequence review for the SGTR accident is discussed in Section 2.9 of this SE.

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 [24]. 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 overtemperature ΔT and low pressurizer pressure, respectively. 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 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 EF to 580 EF, and a SG tube plugging level up to 22 percent. LOOP was assumed in the analyses performed. The licensee provided supplemental information in Section 5.4 of L-05-112 [5] regarding input parameters and assumptions.

The licensee provided its response in RAI 6 of L-05-165 [10], to an NRC staff RAI 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 analysis results. 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 staff found modeling the break at 30 minutes for a thermal hydraulic point acceptable since this was a more conservative approach for calculating the radiological dose release. The operational response analysis, at EPU conditions, showed a break flow termination time greater than 60 minutes and available margin such that no overfill occurred.

The NRC staff reviewed the licensee’s analyses of the SGTR event and concluded that the licensee’s analyses were performed using acceptable analytical models and support operation at the EPU power level. The staff finds the SGTR event analyses for the proposed EPU acceptable since the analyses inputs and steam release values were conservative for this event and no overfilling occurred.

Conclusion

The NRC staff has reviewed the licensee’s analysis of the SGTR accident and concludes that the licensee’s analysis has adequately accounted for operation of the plant at the proposed EPU power level and was performed using acceptable analytical methods and approved computer codes. The staff further concludes that the assumptions used in this analysis are conservative and that the event does not result in an overfill of the faulted SG. Therefore, the staff finds the proposed EPU acceptable with respect to the SGTR event.

2.8.5.6.3 Emergency Core Cooling System (ECCS) and Loss-of-Coolant Accidents (LOCAs) (EPULR Sections 5.2.1 and 5.2.2)

Regulatory Evaluation

LOCAs are postulated accidents that would result in the loss of reactor coolant from piping breaks in the RCPB at a rate in excess of the capability of the normal reactor coolant makeup system to replenish it. Loss of significant quantities of reactor coolant would prevent heat removal from the reactor core, unless the water is replenished. The reactor protection and ECCS systems are provided to mitigate these accidents. The NRC staff's review covered (1) the licensee's determination of break locations and break sizes; (2) postulated initial conditions; (3) the sequence of events; (4) the analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients; (5) calculations of peak cladding temperature, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling; (6) functional and operational characteristics of the reactor protection and ECCS systems; and (7) operator actions. The NRC's acceptance criteria are based on (1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; (2) 10 CFR Part 50, Appendix K, insofar as it establishes required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA; (3) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer; (4) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (5) GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented. Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Best estimate large-break loss-of-coolant accident (BELOCA)

The NRC staff reviewed the licensee's evaluation of the ECCS performance analyses for BVPS-1 and 2, as performed according to the Code Qualification Document (CQD) methodology [50], assuming the proposed EPU conditions. BELOCA analyses were conducted assuming the BVPS-1 and 2 cores were loaded with Westinghouse 17 x 17 RFAs. These analyses were also based upon nominal containment operating pressure conditions consistent with implementation of containment conversion, and considered the BVPS-1 SG replacement.

The BELOCA analyses were performed to demonstrate that the system design would provide sufficient ECCS flow to transfer the heat from the reactor core following a large-break LOCA (LBLOCA) at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling would be prevented, and (2) the clad metal-water reaction would be limited to less than would compromise cladding ductility and result in excessive hydrogen generation. The NRC staff reviewed the analyses to assure that they reflected suitable redundancy in components and features; and suitable interconnections, leak detection,

isolation, and containment capabilities were available such that the safety functions could be accomplished, assuming a single failure, for LBLOCAs considering the availability of onsite and offsite electric power (assuming offsite electric power is not available, with onsite electric power available; or assuming onsite electric power is not available, with offsite electric power available). The acceptance criteria for ECCS performance, provided in 10 CFR 50.46, were used by the staff in assessing the acceptability of the Westinghouse CQD methodology for BVPS-1 and 2. The NRC staff also reviewed the limitations and conditions stated in its SE supporting approval of the Westinghouse CQD methodology and the range of parameters described in the CQD topical report [50] in its assessment of the acceptability of the methodology for BVPS-1 and 2.

The licensee stated, “[b]oth FENOC and its analysis vendor Westinghouse have ongoing processes in place that assure that analysis input values for peak cladding temperature-sensitive parameters bound their as-operated plant values.” [8] The licensee further stated, “. . . Beaver Valley plant-specific LOCA analyses are based on Beaver Valley specific models.” [10] These statements, together with the NRC staff’s review of the results of the BELOCA analyses, provided reasonable assurance that the CQD methodology applies to BVPS-1 and 2, pursuant to 10 CFR 50.46(c)(2), and that the licensee has properly applied it.

In its submittal, the licensee provided the analysis results for the BVPS-1 and 2 BELOCA analyses at the proposed EPU conditions, which were produced in accordance with the CQD methodology. The licensee’s results for the calculated peak cladding temperatures (PCTs), the maximum cladding oxidation (local), and the maximum core-wide cladding oxidation are provided in the following table along with the acceptance criteria of 10 CFR 50.46(b).

LBLOCA Analysis Results for a double-ended guillotine break at the pump discharge

Parameters	BVPS-1	BVPS-2	10 CFR 50.46 Limits
Cladding Material	Zircaloy	Zircaloy	Zircaloy
Peak Clad Temperature	2144 EF	1976 EF	2200 EF (10 CFR 50.46(b)(1))
Maximum Local Oxidation	8.77%	6.7 %	17.0% (10 CFR 50.46(b)(2))
Maximum Total Core-Wide Oxidation (All Fuel)	0.985%	0.91%	1.0% (10 CFR 50.46(b)(3))

In its analyses, the licensee also addressed the concern that zircaloy fuel may have pre-existing oxidation that must be considered in its LOCA analyses. In its response to the NRC staff’s RAI, the licensee indicated that it considered that the zircaloy clad fuel has both pre-existing oxidation and oxidation resulting from the LOCA (pre- and post-LOCA oxidation both on the inside and outside cladding surfaces). The licensee also noted that the fuel with the highest LOCA oxidation will likely not be the same fuel that has the highest pre-LOCA oxidation. The

licensee indicated that when the calculated pre-LOCA oxidation was factored into the licensee's BE LBLOCA analyses for the zircaloy clad fuel, consistent with the Westinghouse CQD methodology, that even during a fuel pin's final cycle in the core, the sum of the calculated pre- and post-LOCA oxidation remained less than the 17-percent acceptance criterion of 10 CFR 50.46(b)(2). The staff finds that this has appropriately addressed the issue with pre-LOCA oxidation.

The concern with core-wide oxidation relates to the amount of hydrogen generated during a LOCA. Because hydrogen that may have been generated pre-LOCA (during normal operation) will be removed from the RCS throughout the operating cycle, the NRC staff noted that pre-existing oxidation does not contribute to the amount of hydrogen generated post-LOCA and therefore it does not need to be addressed when determining whether the calculated total core-wide oxidation meets the 1.0-percent criterion of 10 CFR 50.46(b)(3).

The NRC staff concluded that the results of the licensee's analyses demonstrated compliance with 10 CFR 50.46(b)(1) through (b)(3) for licensed power levels of up to the proposed EPU. Meeting these criteria provides reasonable assurance that at the proposed EPU power level the BVPS-1 and 2 cores will be amenable to cooling as required by 10 CFR 50.46(b)(4). The capability of BVPS-1 and 2 to satisfy the long-term cooling requirements of 10 CFR 50.46(b)(5) were reviewed as part of the licensee's LAR to convert the containments from sub-atmospheric to atmospheric containments [4].

Slot Breaks at the Top and Side of the RCS Cold Leg

The NRC staff requested that the licensee address slot breaks at the top and side of an RCP discharge cold leg pipe that could, under some circumstances, lead to greatly extended periods of core uncovery, resulting in fuel cladding oxidation in excess of the 10 CFR 50.46(b)(2) limit, and also possibly in excess of the total hydrogen generation limit of the 10 CFR 50.46(b)(3) limit. In its response [10], the licensee referred to a generically applicable letter from Westinghouse to the NRC related to this issue. In its response, the licensee also indicated that the operators, acting upon guidance provided in the BVPS-1 and 2 emergency response procedures, would take timely appropriate steps to avoid the conditions necessary for extended core uncovery. Based on its review of this information provided by the licensee, the NRC staff concludes that the licensee's analysis and procedural provisions address and resolve this issue for BVPS-1 and 2. The resolution of this issue applies specifically to the current BVPS-1 and 2 licensing bases and does not, of itself, resolve the generic issue of slot breaks at the top and side of the pipe for any vendor methodology.

Downcomer Boiling

Downcomer boiling can be a concern during recovery of the core after an LBLOCA because the still-hot reactor vessel can heat the water in the downcomer to the point that there is not enough head of water in the downcomer to maintain a reflood rate sufficient to replenish the water boiled off the top of the core. This would result in a fuel temperature rise. It is possible that even after the hottest spot in the core is quenched, that another spot in the core could reheat to an even higher temperature than the original hot spot had attained. The licensee provided the results of analyses it had performed using the approved best estimate CQD methodology [50] in its letter dated July 8, 2005 [10], to demonstrate that following an LBLOCA, BVPS-1 and 2 could attain a stable and sustained core quench. To demonstrate that a stable and sustained

quench would be achieved, the licensee analyzed a scenario with much more severe consequences (e.g., a PCT that is greater than 2300 EF) than the 95th percentile PCT (2144 EF) of the new analysis of record discussed above. In this analysis, a stable and sustained quench of the core was apparent despite the severe core thermal and hydraulic behavior. The NRC staff concludes that this demonstrates that BVPS-1 and 2 can achieve a stable and sustained quench after the most severe LOCA within their design bases.

The NRC staff is presently pursuing concerns related to downcomer boiling generically. If that review raises any concerns applicable to the LOCA analyses at BVPS-1 and 2 which were not considered in this review, then the staff will request the licensee to address these issues consistent with any generic resolution.

SBLOCA

The NRC staff noted that the vendor analysis did not conform to the NRC-approved NOTRUMP SBLOCA method. That is, in the EPU SBLOCA analyses, the vendor changed the NOTRUMP NRC-approved method by allowing all of the loop seals to clear of water for small breaks. The staff noted this and the licensee re-submitted an analysis that conformed to the NRC-approved NOTRUMP SBLOCA methodology. The approved method only allows the broken loop seal piping (suction leg piping) to clear during the blowdown. With one loop seal cleared, the loop resistance is higher, minimizing the two-phase level in the core during the uncovery period, which maximizes PCT for the limiting break.

The NRC staff also notes that the original EPU SBLOCA analysis submittal only contained the results of the 2, 3, and 4-inch breaks for BVPS-1, and the results of the 2 and 3-inch breaks for BVPS-2. The staff questioned the validity of the Westinghouse practice of only analyzing even-integer sized breaks as reported in the licensee's submittals. In these submittals, and as appears to be common in Westinghouse analyses, Westinghouse analyzes the same break spectrum, which includes 1, 2, 3, 4, and 5-inch diameter break sizes. Because the break sizes for this spectrum form a very coarse range of areas which are 0.0055, 0.0218, 0.049, 0.0873, and 0.136 ft^2, respectively, the worst break producing the PCT can be omitted. The timing for core uncovery following an SBLOCA is dependent on the volume in the RCS above the elevation of the break. That is, the time to core uncovery is determined by the time it takes for all of the liquid above the elevation of the break to be expelled through the rupture, plus the time to boil-off the remaining liquid below the break, but above the top elevation of the active core. As such, for the same break size, a plant with a large primary system volume will uncover later in the event since it will take longer for the larger amount of fluid to be expelled through the rupture. Clearly, analyzing the same break spectrum on all plants will, in most cases, preclude identification of the worst break.

This concern has been verified during the recent review of the Waterford EPU. CE-Westinghouse varies the break sizes from 0.5 ft^2 down to and including the break size that does not uncover the core. Moreover, in the vicinity of the limiting break, roughly around break sizes of 0.05 ft^2, breaks on either side of this limiting break are analyzed in increments of approximately 0.01 ft^2. For Waterford, the 0.05 ft^2 cold leg break was identified as the worst case, resulting in a PCT of 1959 EF, as reported in their EPU submittal. The PCT resulting from the 0.06 ft^2 break was found to be 1955 EF, but because the temperature rise for this break was terminated by safety injection tank (SIT) actuation, the licensee was asked to demonstrate that a break between 0.05 and 0.06 ft^2, where SIT actuation would not occur,

would not produce a higher temperature. An additional analysis by CE-Westinghouse showed that the PCT for the 0.055 ft^2 cold leg break was 2018 EF. Thus, a break area resolution of 0.005 ft^2 was required to determine the worst case small break. This resolution is an order of magnitude smaller than that employed for Westinghouse-designed systems when Westinghouse applies their integer break diameter approach.

To compensate for the increased PCT when analyzing only integer break sizes and allowing only the broken loop seal to clear, the licensee proposed increasing the accumulator pressure from 595 psia to 625 psia. Modifications to increase the high pressure SI flow delivery to the RCS were also made and were motivated by the increase in core thermal power level for the EPU conditions. This increased the injection flow by about 5 percent. Both of these modifications help reduce the degree of core uncovery and also the calculated PCTs for BVPS-1 and 2.

The NRC staff evaluation consisted of reviewing the results of the SBLOCA spectrum performed at 2917.4 MWt (100.6 percent of 2900 MWt) and a peak linear heat generation rate of 14.0 kw/ft. The staff also reviewed the results of the post-LOCA long-term cooling analyses to show the plant emergency procedures can properly deal with and control the build-up of boric acid in the RCS following large and SBLOCAs. These two areas of review are discussed separately below. SBLOCA ECCS performance will be discussed first.

The NRC staff performed audit calculations for the BVPS-1 and 2 NSSS using the RELAP5/MOD3 code. The core power level was assumed to be 2917.4 MWt, with the hot rod at the peak linear heat generation rate of 14.0 kw/ft. The model included 24 axial cells to better track the two-phase level in the core, which also included a hot bundle parallel channel containing the hot rod and the same level of axial detail. The top skewed power shape used in the NOTRUMP SBLOCA analysis was also input to the RELAP5/MOD3 code. All three loops in the RELAP5 model were represented explicitly in the nodalization of the BVPS-1 and 2 NSSS. The ECCS was also modeled and included high pressure and low pressure SI pumps along with three accumulators.

As stated above, the initial EPU submittal contained in the EPULR included analysis of the 2, 3, and 4-inch breaks for BVPS-1, and the results of the 2 and 3-inch breaks for BVPS-2. Since the analysis approach of evaluating only integer break sizes does not necessarily identify the limiting break, RAIs were issued by the NRC staff requesting analyses for additional break sizes between the integer sizes. In response, the licensee presented the results of the 1.5, 2.0, 2.25, 2.5, 2.75, 3.0, 3.25, 4.0, 5.0, and 6.0-inch break sizes. Results of the analyses showed that the limiting break for BVPS-1 was calculated to reach 1895.0 EF for the 2.75-inch break size, and the limiting break for BVPS-2 was calculated to reach 1917 EF for the 3-inch break size. The peak local clad oxidation for BVPS-1 was found to be 11.07 percent and for BVPS-2, 13.42 percent for these break sizes. The licensee's initial integer break size analysis showed that for BVPS-1 the PCT was calculated to be 1737 EF for the 3-inch break size and for BVPS-2, the PCT was calculated to be 1758 EF for the 2-inch break size.

The NRC staff performed audit calculations for the small-break spectrum (discharge leg breaks on the bottom of the cold leg) and calculated the PCT for the 2.15-inch break size to be approximately 1910 EF. The staff RELAP5/MOD3 model contained limiting information from both units in a single bounding input model. The staff calculations were found to be consistent with the licensee calculated PCT. The staff also issued RAIs requesting that the licensee

evaluate other break sizes and locations. The licensee performed analyses of similar break sizes on the top of the discharge as well as an analysis of a severed injection with degraded injection into the intact loops. These breaks were found to be less limiting than the cold leg breaks on the bottom of the discharge leg piping. The NRC staff's audit calculations for these alternate break locations also found these breaks to be less limiting.

The NRC staff's RELAP5 calculations for small breaks also showed a DNB condition was achieved in the hot channel causing a first peak during the blowdown. The PCT for these blowdown peaks was calculated to be approximately 2050 EF. The licensee did not calculate that a CHF condition occurs because of differences in the timing of the loss of offsite power. In the NRC staff's calculations, the loss of offsite power was assumed to occur at the worst time following initiation of the LOCA. That is, in the staff's model, the loss of offsite power was assumed to occur at the time the reactor trip signal is generated on a low RCS pressure signal. This loss of offsite power assumption results in tripping the RCPs which begin coasting down, while concurrently, there is a signal delay resulting in a delayed insertion of the scram rods. As a consequence, there are about 2 to 3 seconds of pump coastdown at full power (the bundle flow decreases, the void increases, and the pressure decreases) before the rods have inserted sufficiently to reduce the core power to terminate the rapid clad heatup. The licensee assumes no delay between RCP trip and rod insertion. While this approach has been accepted by the staff previously, the staff plans to review this issue with all vendors to determine if there is a potential generic issue regarding timing for the loss of offsite power following SBLOCAs. The NRC staff notes that even with the early CHF condition, the limits of 10 CFR 50.46 are not expected to be exceeded.

Post-LOCA Long-Term Cooling

The NRC staff also reviewed the large and small-break post-LOCA long-term cooling analyses which deal with the control of boric acid precipitation. The staff performed audit calculations to verify the timing for boric acid precipitation for the limiting LBLOCA event. These evaluations are also discussed below.

The NRC staff performed assessments of the timing for boric acid precipitation following LBLOCAs using the staff models developed for other plant power uprate reviews. The staff's calculations using these models showed that without a core flushing flow, precipitation occurred at 6.3 hours for BVPS-2 (the BVPS-1 precipitation time was calculated to be 7.0 hours and is less limiting). Calculations performed by the licensee showed precipitation would not occur before 6.5 hours. The staff utilized the same boundary conditions as the licensee and included:

- the mixing volume includes 1/2 of the lower plenum, the core, and the portion of the upper plenum below the bottom elevation of the hot legs

- the precipitation limit is conservatively assumed to be 29.27 wt. percent at 14.7 psia

- the decay heat curve uses the 1971 ANS Standard with a 1.2 multiplier

- mixing of 1/2 of the lower plenum was credited. Mixing does not begin in the lower plenum until the concentration in the core reaches 12.3 wt. percent boric acid in the staff model (based on the density of the RWST water at 65 EF).

The NRC staff's evaluations are consistent with the licensee computations for timing of boric acid precipitation and support the realignment to hot leg injection at 6.0 hours for BVPS-2 and 6.5 hours for BVPS-1.

In the EPULR, the licensee provided insufficient information and analyses to demonstrate that boric acid could be controlled following SBLOCAs. For SBLOCAs, the RCS pressure could remain high so that when the switch to simultaneous injection occurs at 6.0 hours, there could be insufficient flow from the high pressure pump to flush the core (i.e. a core flushing flow is the flow in excess of the core/system boil-off rate to ensure boric acid is removed through the break). The NRC staff issued RAIs requesting the licensee discuss the need for analyses of the entire SBLOCA spectrum with identification of all the operator actions and precautions needed to successfully accomplish the core flushing function. The licensee responded by providing an analysis that shows RCS pressure can be reduced below 120 psia prior to 6.0 hours into the event using two out of three SG atmospheric dump valves (ADVs). The operators will commence a cooldown at no later than 1.0 hours after opening of the break. With RCS pressure reduced to at least 120 psia at 6.0 hours, there will be sufficient flushing flow to terminate the increase, and subsequently reduce, the boric acid build-up in the core for SBLOCAs.

Since RCS pressure can remain above 120 psia for hours during an SBLOCA, the NRC staff requested an analysis of the break spectrum to demonstrate that the plant could be cooled down below the RCS pressure at 6.0 hours which is necessary to flush the core prior to reaching the precipitation limit.

The NRC staff notes that each of the BVPS-1 and 2 units have 3 ADVs with a relief capacity of 235,000 lb/hr per valve at 1040 psia. Each unit also has an additional RHR atmospheric steam dump valve with a capacity of 334,000 lb/hr relief capacity. A simple calculation shows that all four valves can pass approximately 34 lbs/sec at 6.0 hours, which is the decay heat steaming rate at this time. Clearly, a single failure of one of these valves would not enable the RCS pressure to be reduced to 120 psia. It is noted that the BVPS-1 and 2 units have three PORVs with a capacity of 210,00 lb/hr each at 2350 psia. Failure of the RHR atmospheric steam dump valve and opening of all three PORVs would not reduce RCS below 120 psia at 6.0 hours. The NRC staff performed an independent analysis to evaluate cooldown and long-term cooling performance following small breaks. Results of the 1, 2, and 3-inch small breaks with failure of one of the ADVs shows that the RCS refills at 1.8, 2.5, and 4.7 hours, respectively for these break sizes. The 4-inch break depressurizes below 100 psia before 6 hours, allowing a core flush. Thus, although the RCS cannot be depressurized below 120 psia prior to 6 hours, refill of the RCS disperses the boric acid throughout the primary system, reducing the concentrations well below precipitation limits. By letter dated July 6, 2006, the licensee provided supporting information to demonstrate cooldown to a pressure below 120 psia prior to the switch to hot leg injection. The staff has reviewed the licensee's analysis and concurs that the licensee has adequately demonstrated that cooldown would occur within 6.0 hours, or for breaks that do not reduce RCS pressure to 120 psia, subcooling and vessel refill would occur at that time.

The NRC staff notes that although RCS pressure may not be reduced below 120 psia at 6.0 hours, the RCS is at a sufficiently high temperature to maintain the boric acid in solution, until refill is initiated. Following the staff's independent analysis, the licensee informed the staff that its analysis of these small breaks using the NRC-approved NOTRUMP computer code verified refill of the RCS prior to 6 hours for break sizes 3 inches or less, thereby ensuring that boric acid is controlled following all small breaks.

Based on the NRC staff's analysis and the licensee's followup verification of the staff's calculations, the staff finds that the analysis and operator actions to cooldown the RCS no later than 1.0 hour post-LOCA are necessary and acceptable to ensure boric acid is controlled for all SBLOCAs. The staff considers the EOP action to initiate cooldown of the RCS no later than 1.0 hour after initiation of the break, following all small breaks, in order to facilitate the successful control of boric acid, sufficient to allow operators to terminate and reduce the boric acid buildup following all LOCAs for BVPS-1 and 2 at EPU conditions. As noted above, consideration of a failure of one of the ADV valves must be considered in the analysis which then demonstrates that even though cooldown is not accomplished within 6 hours, the RCS refill disperses the boric acid and resolves this issue.

The NRC staff reviewed the Westinghouse SBLOCA and post-LOCA long-term cooling analyses for application to the BVPS-1 and 2 NSSS's operating under the proposed EPU conditions. The staff's review confirmed that the licensee and its vendor have processes to assure that the BVPS-1 and 2 plant-specific input parameter values and operator action times (where appropriate) that were used to conduct the analyses will assure that 10 CFR.50.46 limits are not exceeded. Long-term cooling can be assured for all break sizes by providing the means to remove decay heat for extended periods of time, while also preventing the precipitation of boric acid for all break sizes and locations. Furthermore, the staff finds that the analyses were conducted within the conditions and limitations of the NRC-approved Westinghouse NOTRUMP SBLOCA methodology, and that the results satisfy the requirements of 10 CFR 50.46(b), based on operation at the proposed EPU conditions. The staff notes that the procedures for assuring boric acid control for all breaks for the BVPS-1 and 2 units are acceptable and the licensee's approach to be a conservative and acceptable approach for demonstrating core cooling during the long term for all break sizes.

Conclusion

Based on its review, the NRC staff concluded that the Westinghouse CQD methodology [50] is acceptable for use for BVPS-1 and 2 in demonstrating compliance with the requirements of 10 CFR 50.46(b), operating at the proposed EPU conditions, with atmospheric containment pressure and with RSGs for BVPS-1. The staff's conclusion was based, in part, on the fact that the BVPS-1 and 2 analyses were conducted within the conditions and limitations of the NRC-approved Westinghouse CQD methodology, and that the results satisfied the requirements of 10 CFR 50.46(b) based on the EPU power level.

The NRC staff has reviewed the licensee's analyses of the LOCA events and the ECCS. The staff concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and that the analyses were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection system and the ECCS will continue to ensure that the peak cladding temperature, total oxidation of the cladding, total hydrogen generation, and changes in core

geometry, and long-term cooling will remain within acceptable limits. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 4, 27, 35, and 10 CFR 50.46 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the LOCA.

The staff notes that, to support the acceptability of the BVPS-1 and 2 units operating at EPU conditions, these conclusions are based on the condition that cooldown following all small breaks begins no later than 1.0 hr. following opening of the break. The operators should be especially cautioned to not suddenly depressurize the RCS should boiling persist for more than 6 hours. Adherence to the 100 EF/hr cooldown limit should be noted to preclude an inadvertent precipitation.

Based on its review of the licensee's small break and post-LOCA long-tem cooling analyses, the NRC staff concludes that the Westinghouse NOTRUMP SBLOCA methodology and post-LOCA long term cooling evaluation, is acceptable for use for BVPS-1 and 2 in demonstrating compliance with the requirements of 10 CFR 50.46(b), under the proposed EPU conditions. The licensee, by letter dated July 6, 2006, submitted additional analyses to show that small breaks can be cooled down to an RCS pressure of 120 psia, with a failure of one of the ADVs. The licensee also demonstrated that for those breaks which cannot be depressurized below an RCS pressure of 120 psia in order to flush the core, the RCS can be shown to refill and re-establish subcooled natural circulation. The necessary operator actions to facilitate a successful control of boric acid would also need to be included in the EOPS. If the RCS is shown to remain above 120 psia and boil for an extended time beyond the 6-hour switch time, then additional EOP cautions or guidance would be needed to preclude the operators from an inadvertently rapid depressurizing with high concentrations of boric acid in the RCS.

2.8.5.7 Anticipated Transient Without Scram (ATWS) (EPULR Section 5.8)

Regulatory Evaluation

ATWS is defined as an anticipated operational occurrence followed by the failure of the reactor portion of the protection system specified in GDC 20. For Westinghouse plants, 10 CFR 50.62 requires that each PWR must have equipment that is diverse from the reactor trip system to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must perform its function in a reliable manner and be independent from the existing reactor trip system.

The NRC staff's review was conducted to ensure that (1) the above requirements are met, and (2) the setpoints for the ATWS mitigating system actuation circuitry (AMSAC) remain valid for the proposed EPU. In addition, for Westinghouse plants (e.g., BVPS-1 and 2), the staff verified that the consequences of an ATWS are acceptable. The acceptance criterion is that the peak primary system pressure should not exceed the ASME Service Level C limit of 3200 psig. The peak ATWS pressure is primarily a function of the moderator temperature coefficient (MTC) and the primary system relief capacity. The staff reviewed (1) the limiting event determination, (2) the sequence of events, (3) the analytical model and its applicability, (4) the values of parameters used in the analytical model, and (5) the results of the analyses. The staff reviewed the licensee's justification of the applicability of generic vendor analyses to its plant and the operating conditions for the proposed EPU. Review guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The final ATWS rule, 10 CFR 50.62(c)(1), requires the incorporation of a diverse actuation of the AFW system and the 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 predicted in the ATWS evaluation should be comparable to the peak RCS pressures reported for generic ATWS analyses, conducted by Westinghouse in 1979 [51], and must not exceed the ASME Code Service Level C limit of 3200 psig. This approach is suitable for BVPS-2, since its design features are covered by the Westinghouse generic analyses. The peak pressure, calculated for a loss-of-load ATWS, for a three-loop plant (2785 MWt core power), equipped with model 51 SGs, was 2861 psia [51]. The results of sensitivity studies [51] indicated that peak pressure would increase by 24 psi if power level is increased by 2 percent. Therefore, increasing core power by 4.13 percent to 2900 MWt, would increase the peak pressure to almost 2952 psia, well below the ASME Code Service Level C limit.

This approach, however, is not suitable for BVPS-1, since it is equipped with RSGs that are not covered by the Westinghouse generic analyses. In response to an RAI question, the licensee supplied the results of an ATWS analysis that was performed by Westinghouse for the BVPS-1 plant, as equipped with model 54F RSGs, at the proposed EPU power level [10]. For the loss-of-load ATWS event, Westinghouse calculated that the peak pressure attained would be 3060 psia, still below the 3200 psig ASME Code Service Level C limit. Westinghouse also verified that the peak differential pressure, across the tubes and tubesheet of the model 54F RSGs remains below the ASME Code Service Level C limit of 3276 psi.

During an audit at Westinghouse-Monroeville in November 2005, the NRC staff reviewed the Westinghouse engineering calculations supporting this event. The staff concluded that the licensee had demonstrated that the analytical basis for the final ATWS rule continues to be met for operation of BVPS-1 with the model 54F RSGs and of BVPS-2 with the model 51 OSGs, under EPU conditions.

Conclusion

The NRC staff has reviewed the information submitted by the licensee related to ATWS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on ATWS. The staff concludes that the licensee has demonstrated that the AMSAC will continue to meet the requirements of 10 CFR 50.62 following implementation of the proposed EPU. Additionally, the licensee has demonstrated, as explained above, that the peak primary system pressure following an ATWS event will remain below the acceptance limit of 3200 psig. Therefore, the staff finds the proposed EPU acceptable with respect to ATWS.

2.8.6 Fuel Storage

2.8.6.1 New Fuel Storage

Regulatory Evaluation

Nuclear reactor plants include facilities for the storage of new fuel. The quantity of new fuel to be stored varies from plant to plant, depending upon the specific design of the plant and the individual refueling needs. The NRC staff's review covered the ability of the storage facilities to maintain the new fuel in a subcritical array during all credible storage conditions. The review focused on the effect of changes in fuel design on the analyses for the new fuel storage facilities. The NRC's acceptance criteria are based on GDC 62, insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.1.

Technical Evaluation

The current new fuel storage analyses for BVPS-1 and 2 has been established at 5.0 weight percent uranium-235. This supports the EPU conditions. There are also no changes in fuel design characteristics that would effect the criticality analyses for fuel storage. In response to NRC staff inquiries, the licensee stated that the RFA fuel geometry/characteristics remain the same as the V5H fuel assemblies. The major change to the fuel assembly from V5H to RFA was the redesigned mid-grids and the addition of intermediate flow mixing grids. These items do not impact the criticality analyses for the units. Therefore, the staff finds that the EPU will not affect the ability to store new fuel in a subcritical configuration.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the new fuel on the analyses for the new fuel storage facilities and concludes that the new fuel storage facilities will continue to meet the requirements of GDC 62 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the new fuel storage.

2.8.6.2 Spent Fuel Storage

Regulatory Evaluation

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the spent fuel pool (SFP) and storage racks is to maintain the spent fuel assemblies in a safe and subcritical array during all credible storage conditions and to provide a safe means of loading the assemblies into shipping casks. The NRC staff's review covered the effect of the proposed EPU on the criticality analysis (e.g., reactivity of the spent fuel storage array and boraflex degradation or neutron poison efficacy). The NRC's acceptance criteria are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and (2) GDC 62, insofar as it requires that criticality in the fuel storage systems be prevented by physical systems or processes, preferably by use of geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.2.

Technical Evaluation

The NRC staff reviewed the current SFP licensing basis. BVPS-1 SFP allows for fuel that is enriched up to 5.0 weight percent uranium-235. Spent fuel can be stored in three regions

based upon enrichment and burnup. The storage racks have Boral neutron absorber panels. BVPS-1 is currently operating under a 10 CFR 70.24 exemption. The staff finds that the current licensing basis bounds that for EPU and, therefore, finds it acceptable for EPU conditions.

BVPS-2 spent fuel storage also allows for fuel that is enriched up to 5.0 weight percent uranium-235. Spent fuel can be stored in three regions based upon enrichment and burnup. The storage racks have Boraflex neutron absorber panels, however the licensee does not take credit for the boron content in the panels. The licensee has restrictions on the placement of assemblies within a region (i.e., checkerboard) based upon its enrichment and burnup. The BVPS-2 spent fuel pool takes credit for 2000 ppm soluble boron. The criticality analysis uses reactivity equivalencing. There are known non-conservatisms associated with the Westinghouse reactivity equivalencing methodology (WCAP-14416) specifically related to the uniform burnup profile assumed. This is non-conservative because the fuel is burned less at the top and bottom due to neutron leakage in a reactor, causing it to have higher reactivity in these areas once disposed into the SFP. The current BVPS-2 licensing basis includes an analysis to account for this non-conservative assumption. In response to NRC staff RAIs, the licensee stated that the additional burnup that may be realized for EPU will tend to flatten the burnup distribution lessening the axial burnup bias for burnup credit. The staff agrees with this statement, therefore the staff finds that the current licensing basis is still bounding for EPU conditions. BVPS-2 was operating under a 10 CFR 70.24 exemption. In response to NRC staff RAIs, the licensee has committed to meet 10 CFR 50.68 and has provided information demonstrating that they meet this regulation. The staff has reviewed this information and finds that BVPS-2 meets 10 CFR 50.68 for EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the spent fuel storage capability and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the spent fuel rack temperature and criticality analyses. The staff also concludes that the SFP design will continue to ensure an acceptably low temperature and an acceptable degree of subcriticality following implementation of the proposed EPU. Based on this, the staff concludes that the spent fuel storage facilities will continue to meet the requirements of GDCs 4 and 62 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to spent fuel storage.

2.9 Source Terms and Radiological Consequences Analyses

To support the proposed EPU, this LAR also requests implementation of a full-scope reactor accident alternative source term (AST) pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50.67, and using RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors." As part of the proposed EPU, the licensee also requested changes to the BVPS-1 TSs to increase the primary and secondary coolant activity limits to reflect the RSGs. Specific TS changes requested are listed and evaluated in Section 2.9.8, "Technical Specification Changes," of this SE.

The current BVPS-1 and 2 DBAs analyzed for radiological consequences at the exclusion area boundary (EAB), low-population zone (LPZ), and control room (CR) in Section 14, "Accident

Analyses," of the BVPS-1 UFSAR and Chapter 15, "Accident Analyses" of the BVPS-2 UFSAR includes the following nine events:

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

The licensee previously requested a 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 License Amendment Nos. 257 and 139 for BVPS-1 and 2, respectively, dated September 10, 2003 (ADAMS Accession No. ML032530204). In the LAR associated with License Amendment Nos. 257 and 139, the licensee requested, and the staff approved, the implementation of the AST at an uprated reactor core thermal power level of 2918 MWt which includes an uncertainty of 0.6 percent for calorimetric thermal power measurement (EPU conditions). The NRC staff approved the use of 0.6 percent calorimetric thermal power measurement allowance (instead of the 2 percent recommended in RG 1.49) in License Amendment Nos. 243 and 122 dated September 24, 2001 (ADAMS Accession No. ML012490569). The current LAR proposes to increase the licensed power level from 2689 MWt to 2900 MWt which is an approximate 8-percent increase in reactor power.

The licensee also previously requested a license amendment for operation of BVPS-1 with the RSGs at the current reactor power level of 2689 MWt and implementing the AST for the MSLB, SGTR, LRA, LACP, and SLB accidents. However, the radiological consequence analyses for these accidents were performed at the EPU conditions. The NRC staff approved the MSLB, SGTR, LRA, LACP, and SLB radiological consequence analyses on February 9, 2006, with the issuance of License Amendment No. 273 for BVPS-1 (ADAMS Accession No. ML060240146). For the LRA, LACP, and SLB accidents, all parameters, assumptions, accident sequences, and analysis methods used in the radiological consequence analyses are the same for both BVPS-1 with the RSGs and BVPS-2 with the OSGs since bounding parameters were used to make the dose consequence analyses applicable to either unit. Therefore, the radiological consequence analyses performed at the EPU conditions for the LRA, LACP, and SLB accidents in License Amendment No. 273 bound those accidents for BVPS-2. In this current LAR, the licensee analyzed the radiological consequences resulting from the MSLB and SGTR accidents for BVPS-2 with the OSGs at the EPU conditions (see Sections 2.9.2 and 2.9.3 of the EPULR).

Therefore, the majority of DBAs have already been analyzed for the EPU conditions by the licensee, as found acceptable in License Amendment Nos. 257 and 273 BVPS-1 and License Amendment No. 139 for BVPS-2. In order to support the current EPU LAR, the licensee analyzed the following remaining four events which were directly impacted by the EPU:

- MSLB Accident for BVPS-2 only
- SGTR Accident for BVPS-2 only
- FHA for BVPS-1 and 2

- WGSR Event for BVPS-1 and 2

On November 29 and 30, 2005, the NRC staff met with the licensee at the BVPS site and performed an audit on the 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 these DBAs listed above 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.

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with EPUs to ensure the adequacy of the sources of radioactivity used by the licensee as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes. The staff's review included the parameters used to determine (1) the concentration of each radionuclide in the reactor coolant, (2) the fraction of fission product activity released to the reactor coolant, (3) concentrations of all radionuclides other than fission products in the reactor coolant, (4) leakage rates and associated fluid activity of all potentially radioactive water and steam systems, and (5) potential sources of radioactive materials in effluents that are not considered in the plant's UFSAR related to liquid waste management systems and gaseous waste management systems.

The NRC staff's acceptance criteria for source terms are based on (1) 10 CFR Part 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas; (2) 10 CFR Part 50, Appendix I, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" criterion; and (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 11.1.

Technical Evaluation

The core isotopic inventory is a function of the core power level and reactor coolant activity concentrations are a function of the core power level, leakage from the fuel, radioactive decay and removal by coolant purification systems. The licensee recalculated the maximum reactor coolant fission product activity concentration assuming 1.0 percent failed fuel, the expected reactor coolant concentrations source terms for radioactive liquid and gaseous effluents for the higher proposed reactor power. The licensee also calculated the core isotopic inventory for the higher proposed reactor power for use in accident dose and equipment qualification dose evaluations.

The licensee calculated the maximum reactor coolant fission product activity concentration assuming 1.0 percent failed fuel using the methods and models outlined in the BVPS-1 and 2 UFSARs. The calculations assumed operation at a core power of 2918 MWt and for 518

effective full-power days. The assumed core power of 2918 MWt includes a power uncertainty of 0.6 percent. Other inputs and assumptions were unchanged from the original BVPS-1 and 2 design basis as specified in the UFSARs. The NRC staff finds that the licensee has used the appropriate core power assumptions for the EPU. The staff also finds that the EPU would not impact any of the other inputs and assumptions to the maximum coolant concentration calculations, so continued use of the current UFSAR values is acceptable. The staff finds that the licensee has appropriately calculated the maximum reactor coolant fission product activity concentration for the EPU.

The licensee calculated the EPU design-basis and TS reactor coolant fission product activity concentration using Stone & Webster computer code, ACTIVITY2, which was accepted by the NRC in Amendment Nos. 257 and 139. The NRC staff previously reviewed and accepted the BVPS-1 and 2 reactor core activity inventory and the primary coolant activity at EPU conditions in Amendment Nos. 257 and 139. The licensee compared the uprated design-basis maximum and average reactor coolant concentrations as limited by the TSs and the BVPS-1 and 2 current design-basis source terms in the UFSAR and found the current design-basis source terms and resultant dose rates bound the EPU conditions.

The licensee used the PWR-GALE code in NUREG-0017, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors," to calculate the source terms for radioactive liquid and gaseous effluents for the uprated power. The NRC staff finds the PWR-GALE code to be an acceptable methodology for this calculation. The licensee provided calculations to show that BVPS-1 and 2 would continue to meet their design basis by meeting the requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC 60 with EPU source terms.

Conclusion

The NRC staff has reviewed the radioactive source term associated with the proposed EPU and concludes that the proposed parameters and resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. The staff further concludes that the proposed radioactive source term meets the requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC 60. Therefore, the staff finds the proposed EPU acceptable with respect to source terms.

2.9.2 Main Steam Line Break (MSLB) Accident Outside Containment (for BVPS-2)

Regulatory Evaluation

The NRC staff reviewed the analyses of the radiological consequences of an MSLB outside the containment. The staff's review included (1) the sequence of events, models and assumptions used by the licensee for the calculation of the radiological doses, (2) evaluation of the TSs on the primary and secondary coolant iodine activities, and (3) determination of reactor coolant iodine concentration corresponding to a preaccident iodine spike and a concurrent iodine spike. The NRC's acceptance criteria for the radiological consequences of an MSLB outside containment are based on (1) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 Rem total effective dose equivalent (TEDE) for the duration of the accident and (2) 10 CFR 50.67, insofar as it

establishes requirements for assuring that radiological doses from postulated accidents will be acceptably low. Specific review criteria are contained in SRP Section 15.0.1.

Technical Evaluation

The NRC staff previously evaluated the radiological consequences for the MSLB and SGTR accidents for BVPS-1 in Amendment No. 273 in support of the BVPS-1 operation with the RSGs at an extended reactor core power level of 2918 MWt and implementing the AST. The NRC staff concluded in Amendment No. 273 that the EAB, LPZ, and CR doses estimated by the licensee for the MSLB and SGTR for BVPS-1 met the dose guidelines provided in 10 CFR 50.67 and accident dose criteria specified in SRP 15.0.1.

For BVPS-2, the licensee re-analyzed the radiological consequences resulting from the postulated MSLB accident for operation with the OSGs at the EPU conditions. The licensee stated, and the NRC staff noted during the audit at BVPS, that the analysis methods used for the radiological consequence analyses for the MSLB and SGTR are the same for both BVPS-1 with the RSGs and BVPS-2 with the OSGs. The major parameters and assumptions used are very similar, except the amount of accident-induced leakage rate into the affected BVPS-2 OSGs during the MSLB accident is 2.1 gpm which is based on the BVPS-2 SG alternative repair criteria (ARC). The primary-to-secondary leakage rate for the BVPS-1 RSGs is 150 gallons-per-day (gpd) per SG.

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. In the MSLB accident scenario, a reactor trip occurs, main steam isolation occurs, safety injection actuates, and a LOOP occurs concurrently with the reactor trip. Steam from the affected SG is released directly to the environment from the SLB point. The licensee assumed that the affected SG will rapidly depressurize and boil dry, releasing the entire content of liquid inventory and entrained radionuclides of the affected SG instantaneously 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 MSSVs and ADVs in the unaffected SGs until the RHR system starts shutdown cooling. There are a total of 3 SGs. The MSLB accident is described in the BVPS-2 UFSAR, Section 15.1.5, “Spectrum of Steam System Piping Failure Inside and Outside Containment.” 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-2 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-2 UFSAR as a design basis and the licensee’s analysis showed that this assumption is not impacted by the EPU conditions. 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-2 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 TS. 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-2 UFSAR and this value was reviewed and accepted by the NRC staff previously in Amendment Nos. 257 and 139 [57], and 273 [6] as a design basis. The EPU conditions do not impact the iodine spiking duration.

Leakage from the RCS to the SGs is assumed to be the maximum value permitted by TSs (150 gpd per SG). The amount of accident-induced leakage into the affected SG is assumed to be 2.1 gpm based on the BVPS-2 ARC. The release from the affected SG due to primary-to-secondary leakage continues for 21 hours until the RHR system brings the primary coolant temperature down to 212 EF. The primary coolant leaked into the affected SG is assumed to immediately flash to steam and be released to the environment without holdup or dilution. The leakage in the unaffected 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 unaffected 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 unaffected SGs, and assumed no iodine partitioning in the affected SG.

The licensee conservatively assumed manual initiation of the control room emergency ventilation system (CREVS) and that a pressurized control room is available at 30 minutes following the MSLB event. The control room 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 2.9.6 of this SE, “Control Room Habitability”).

<u>Conclusion</u>

The NRC staff has evaluated and confirmed by audit at BVPS-1 and 2, the licensee’s accident analyses for the radiological consequences of an MSLB outside containment and concludes that the licensee has adequately accounted for the effects of the proposed AST and EPU. The staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated MSLB outside containment since the calculated TEDE at the EAB and the LPZ outer boundary and in the control room meet the exposure guideline values specified in 10 CFR 50.67 and GDC 19 and the dose acceptance criteria in SRP 15.0.1. Therefore, the staff finds the licensee’s proposed implementation of an AST and EPU acceptable with respect to the radiological consequences of MSLB accidents outside the containment. The assumptions found acceptable to the staff are presented in Table 2 and the licensee’s calculated dose results are given in Table 1 (Tables 1-4 are located just after Section 2.9.8.2 of this SE).

2.9.3 Steam Generator Tube Rupture (SGTR) Accident (for BVPS-2)

<u>Regulatory Evaluation</u>

The NRC staff reviewed the analysis of the radiological consequences of a postulated SGTR. The staff’s review included (1) a review of the sequence of events and plant procedures for recovery from the accident to ensure that the most severe case of radioactive releases has

been considered, (2) a review of the models and assumptions for the calculation of the radiological doses for the postulated accident, (3) an evaluation of the TSs on the primary and secondary coolant iodine activity concentration, and (4) an evaluation of the radiological consequences of an SGTR concurrent with a LOOP and the most limiting single failure. The staff's review included two cases for the reactor coolant iodine concentration corresponding to a preaccident iodine spike and a concurrent iodine spike. The NRC's acceptance criteria for the radiological consequences of an SGTR are based on (1) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 Rem TEDE for the duration of the accident, and (2) 10 CFR 50.67, insofar as it establishes requirements for assuring that radiological doses from postulated accidents will be acceptably low. Specific review criteria are contained in SRP Section 15.0.1.

Technical Evaluation

The NRC staff previously evaluated the radiological consequences for the SGTR accidents for BVPS-1 in Amendment No. 273 in support of the BVPS-1 operation with the RSGs at a reactor core power level of 2918 MWt and implementing the AST. The staff concluded in Amendment No. 273 that the EAB, LPZ, and CR doses estimated by the licensee for the SGTR for the BVPS-1 met the dose guidelines provided in 10 CFR 50.67 and accident dose criteria specified in SRP 15.0.1.

For BVPS-2, the licensee re-analyzed the radiological consequences resulting from the postulated SGTR accidents for operation with the OSGs at the EPU conditions. The licensee stated, and the NRC staff found during the audit at BVPS, that the analysis methods used for the radiological consequence analyses for the SGTR are the same for both BVPS-1 with the RSGs and BVPS-2 with the OSGs. The major parameters and assumptions used are very similar.

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 licensee revised the thermal-hydraulic analysis to provide additional operator action time to isolate a failed open SG ADV on the ruptured SG and calculated an isolation time (termination of break flow) of 65.5 minutes. Based on its review of accident sequence of events, the NRC staff finds the calculated isolation time to be reasonable and, therefore, acceptable.

Appendix F of RG 1.183 identifies acceptable radiological analysis assumptions for an SGTR and this event is described in the BVPS-2 UFSAR Section 15.6.3, "Steam Generator Tube Failure." 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-2 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 2.9.2 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-2 TSs. The iodine activity from the flashed portion of 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 SG 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 1.0 percent of the radionuclides in the unaffected SG 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 control room is purged at a rate of 16,200 cfm for a period of 30 minutes (see Section 2.9.6 of this SE).

Conclusion

The NRC staff has evaluated the licensee’s revised accident analyses for the radiological consequences of an SGTR and concludes that the licensee has adequately accounted for the effects of the proposed AST and EPU on these analyses. The staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of an SGTR accident since the calculated TEDE at the EAB and the LPZ outer boundary do not exceed the exposure guideline values of 10 CFR 50.67 (assuming a preaccident iodine spike) and are a small fraction of the 10 CFR 50.67 values for the concurrent iodine spike. Additionally, the control room TEDE is within the exposure guideline value specified in GDC 19. Therefore, the staff finds the licensee’s proposed AST and EPU acceptable with respect to the radiological consequences of an SGTR. The assumptions found acceptable to the staff are presented in Table 3 and the licensee’s calculated dose results are given in Table 1.

2.9.4 Fuel-Handling Accidents (FHAs) for BVPS-1 and 2

Regulatory Evaluation

The NRC staff reviewed the analyses of the radiological consequences of a postulated FHA. The purpose of this review was to evaluate the adequacy of system design features and plant procedures provided for the mitigation of the radiological consequences of accidents that involve damage to spent fuel. The NRC staff’s review included (1) the sequence of events, models, and assumptions used by the licensee for the calculation of radiological doses, and (2) the adequacy of the ESFs provided for the purpose of mitigating potential accident doses. The NRC’s acceptance criteria for the radiological consequences of FHAs are based on (1) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 Rem TEDE for the duration of the accident, (2) GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate containment, confinement, and filtering systems, and (3) 10 CFR 50.67, insofar as it establishes requirements for assuring that radiological doses from postulated accidents will be acceptably low. Specific review criteria are contained in SRP Section 15.0.1.

Technical Evaluation

The licensee previously analyzed the FHA at a reactor power level of 2705 MWt implementing the AST and submitted it for the NRC approval with a submittal dated March 19, 2001. The NRC staff approved the FHA radiological consequence analysis with Amendment Nos. 241 and 121, issued on August 30, 2001 (ADAMS Accession No. ML012330496). In the EPU LAR, the licensee re-analyzed the radiological consequence of an FHA for the EPU. The FHA radiological consequence analysis is based on the current licensing-basis DBA dose analyses as documented in the BVPS-1 and 2, UFSAR Sections 14.2.1 and 15.7.4, respectively. The updated FHA analysis assumed a core power of 2918 MWt, which reflects the proposed EPU power with 0.6 percent measurement uncertainty. In Amendment Nos. 241 and 121, the NRC staff found and concluded that the licensee used analysis methods and assumptions consistent with the conservative guidance of RG 1.183. The proposed EPU would cause no other changes to inputs and assumptions for the FHA.

The FHA assumes the dropping of a spent fuel assembly during refueling. This event could occur inside the containment or in the fuel building. The BVPS-1 and 2 TS Limiting Condition for Operation (LCO) 3.9.3, “Refueling Operations - Decay Time” requires the reactor to be subcritical for at least 100 hours prior to moving irradiated fuel. This requirement prohibits initiation of fuel handling activities in the fuel pool or in the containment until 100 hours after reactor shutdown. The FHA assumes 137 of the 264 fuel rods in a fuel assembly are damaged and the radionuclide inventory in the fuel rod gap of the damaged fuel rods is assumed to be instantaneously released. These assumptions are current BVPS design and licensing bases which are documented in the BVPS-1 and 2 UFSARs and were previously accepted by the NRC in Amendment Nos. 241 and 121. A radial peaking factor of 1.75 is conservatively applied to the EPU core average gap activity.

The licensee assumed all fission products released from the damaged fuel rods are released to the fuel pool or reactor cavity. The licensee further assumed no decontamination for noble gases, an effective decontamination factor of 200 for radioiodines, and retention of all aerosol and particulate radionuclides within the spent fuel pool or reactor cavity water. The licensee then assumed that all noble gases and iodine from the spent fuel pool or reactor cavity are released from either open containment or open fuel building to the environment in 2 hours without any credit for filtration, holdup, or dilution. Appendix B of RG 1.183 identifies acceptable radiological analysis assumptions for an FHA. All of the above licensee’s assumptions are consistent with the guidance provided in RG 1.183 with no exception.

The licensee claimed no credit for fission product removal by the CREVS following an FHA and assumed the CR is maintained in normal ventilation mode. Following termination of the environmental release at 2 hours, for BVPS-1 only, the CR is purged at a rate of 16,200 cfm for a period of 30 minutes (see Section 2.9.6 of this SE). Since the containment and fuel buildings are assumed “open,” the fission product release from the containment or fuel pool could occur from the containment equipment hatch, containment personnel hatch, fuel building ventilation vent, the BVPS-1 ventilation vent, or the BVPS-2 ventilation vent. The licensee assumed the most restrictive release point which provides the most conservative CR relative concentration (χ/Q value) for the unit-specific FHA analysis, i.e., the BVPS-1 ventilation vent to the BVPS-1 CR air intake and the BVPS-2 ventilation vent to the BVPS-2 CR air intake, respectively (see Section 2.9.7 of this SE, “Atmospheric Dispersion”).

Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of FHAs and concludes that the licensee has adequately accounted for the effects of the proposed AST and EPU on these analyses. The staff further concludes that the plant site and the dose-mitigating engineered safety features remain acceptable with respect to the radiological consequences of a postulated FHA since the calculated TEDE at the EAB and the LPZ boundary are well within the exposure guideline values of 10 CFR 50.67 and the CR TEDE is within the exposure guideline value specified in GDC 19. Therefore, the staff finds the licensee's proposed AST and EPU acceptable with respect to the radiological consequences of FHAs. Assumptions used by the licensee and evaluated by the staff are listed in Table 4. The licensee's calculated dose results are given in Table 1.

2.9.5 Waste Gas System Rupture (WGSR) Event (for BVPS-1 and 2)

Regulatory Evaluation

The NRC staff reviewed the original analysis of the radiological consequences of a postulated WGSR event submitted in the current LAR. The purpose of this review was to evaluate the adequacy of system design features and plant procedures provided for the mitigation of the radiological consequences of accidents that involve waste gas system rupture. The staff's review included the sequence of events, models, and assumptions used by the licensee for the calculation of radiological doses. The NRC's acceptance criteria for the radiological consequences of the WGSR event are based on (1) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the CR under accident conditions without personnel receiving radiation exposures in excess of 5 Rem TEDE for the duration of the accident, and (2) the current BVPS-1 and 2 design-basis dose criterion of 0.5 Rem whole body to any individual in an unrestricted area.

Technical Evaluation

The accident considered is a rupture of the gaseous waste system that releases the entire inventory of the gaseous waste delay beds to the environment with no hold-up, dilution, or filtration. The gaseous waste system collects non-condensable gases from the RCS letdown degasifiers and other sources, processes the gas through the charcoal delay system, and releases it to the environment in a controlled manner. This event is not specifically addressed in RG 1.183, in an SRP chapter, a RG, or in RS-001. The NRC staff relied upon (1) the current BVPS licensing and design bases documented in the BVPS-1 and 2 UFSARs, Section 14.2.3.1, (2) operational limits specified in the BVPS-1 and 2 Offsite Dose Calculation Manual (ODCM) as referenced in the BVPS TSs, and (3) Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Releases Due to a Waste Gas System Leak or Failure," which is contained in SRP 11.3, "Gaseous Waste Management Systems."

The current design and licensing basis as documented in the BVPS-1 and 2 UFSARs, Section 14.2.3.1 states:

> The maximum EAB and LPZ doses that may result due to a failure of the gaseous waste system are a small fraction of the 10 CFR 100.11 limits of 25 rem whole body and 300 rem thyroid, and are within the 0.5 rem whole-body dose specified in NUREG-0800, ESTB 11-5.

In addition, the BVPS-1 and 2 ODCM, Section 3.11.2.5, “Gas Storage Tanks,'” specifies operational limits of less then 52,000 and 19,000 Xe-131 equivalent curies for BVPS-1 and 2, respectively, in any gaseous waste storage tank in accordance with the BVPS-1 and 2 TSs, Administrative Controls Section 6.8.6 c, “Explosive Gas and Storage Tank Radioactivity Monitoring Program.” These limits are based on 0.5 Rem whole body to any individual in an unrestricted area and are independent of the reactor power levels. These limits are not changed and not impacted by the EPU conditions. The licensee has not proposed new limits for the total amounts of radioactive gas in any gaseous waste storage tank for the EPU conditions.

Nevertheless, the licensee reanalyzed the WGSR event at the EPU conditions since it was analyzed and documented in the BVPS-1 and 2 UFSARs. Since RG 1.183 does not address this event, the licensee originally proposed in this LAR, a dose criterion of a 0.5 Rem TEDE. This proposed criterion was not acceptable to the NRC staff.

Item B.I.(a), Criteria of BTP ETSB 11-5 of SRP 11.3 states,

> ...the resulting total body exposure to an individual at the nearest exclusion boundary will not exceed 0.5 Rem. This is consistent with the guidelines of 10 CFR Part 20 and is substantially below the guidelines of 10 CFR Part 100.

The criterion in BTP 11-5 was written prior to Part 20 being expressed in terms of TEDE dose. Rather, the criterion was based upon the Part 20 doses which were in effect at the time, the total body dose. Application of the present Part 20 dose criteria of TEDE to BTP ETSB 11-5 equates to a dose limitation of 0.1 Rem TEDE.

During the NRC staff’s audit on November 29 and 30, 2005, the staff stated that the licensee has the option of retaining the present design-basis criterion for the release of the contents of a waste gas decay tank at 0.5 Rem total body or, if they desire to change to TEDE, the licensee must establish the new criterion at 0.1 Rem TEDE. In its submittal dated December 30, 2005, the licensee opted to retain the present criterion for the release of the contents of a waste gas decay tank at 0.5 Rem whole body to any individual in an unrestricted area and revised the EPU LAR accordingly.

The licensee stated, and the NRC staff agrees, that neither the implementation of the AST, nor the SG replacement will impact the WGSR event. However, this event will be impacted by the EPU conditions. Therefore, the licensee recalculated the radiological consequences resulting from the WGSR event using the same current design-basis parameters and assumptions in the BVPS-1 and 2 UFSARs previously accepted by the staff. The licensee concluded in its December 30, 2005, submittal that the impact of EPU is limited to slight changes in the reactor coolant system mass and fission product inventory in the reactor core while operating with 1.0 percent failed fuel and that any increase in the radiological consequences resulting from these changes is minimal. The licensee further stated that this minimal change meets the criteria for implementation via the 10 CFR Part 50.59 process.

Conclusion

The NRC staff concludes that the dose estimated by the licensee for the WGSR event still meets the applicable design basis dose criterion of 0.5 Rem whole body to any individual in an unrestricted area, as specified in the BVPS-1 and 2 ODCM and TSs. Therefore, the staff concludes that the WGSR event at EPU conditions is acceptable. The basis for the staff's acceptance is retaining the current design-basis operational limits (in the BVPS-1 and 2 TSs and ODCM) of the radioactive gas that is allowed to be stored in any gaseous waste decay tank at the EPU conditions meeting the applicable design-basis dose criterion of 0.5 Rem whole body to any individual in an unrestricted area as specified in the BVPS-1 and 2 ODCM and TSs.

2.9.6 Control Room Habitability

The BVPS-1 and 2 CR habitability was previously evaluated and found acceptable by the NRC in Amendment Nos. 257 and 139 for the LOCA and CREA for BVPS-1 and 2. It was also previously evaluated and found acceptable by the NRC in Amendment No. 273 for the MSLB, SGTR, LRA, LACP, and SLB for BVPS-1. For completeness, the CR habitability evaluation performed in Amendment No. 273, Section 3.2, "Control Room Habitability," is reproduced here in its entirety, supplementing it for the FHA.

The BVPS-1 and 2 CRs are located within a common CR envelope. The common CR 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 SGTR, LRA, LACP, and SLB in Amendment No. 273, and in this EPU LAR for the SGTR and FHA, the licensee assumed that the CR is maintained in normal ventilation mode without activating the CREVS during the entire duration of these accidents. For BVPS-1 and 2, emergency power is provided to the normal CR ventilation system, including all ventilation system components that are required to support CR operation in the recirculation mode. Therefore, the staff finds that it is acceptable to credit the normal ventilation system for post-accident CR purging at the times specified in the accident analyses.

For the MSLB accident for BVPS-1, with the RSGs, and for BVPS-2, with the OSGs, 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 air radioactivity concentrations. The licensee used 600 cfm CREVS flow rate in its radiological consequence analyses including the LOCA and CREA in Amendment Nos. 257 and 139.

The licensee assumed the CR unfiltered air inleakage of 300 cfm during the CR isolation (recirculation) mode and assumed the control room is isolated from 77 seconds to 30 minutes. For the emergency pressurized mode, the licensee assumed the CR is pressurized from 30 minutes to 30 days for the LOCA and the CREA, and to 24 hours for the MSLB, and the licensee assumed the CR 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 egress 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 CR in both the isolated (recirculation) and emergency pressurized modes in May of 2001, using the methodology described in American Society for Testing and Materials (ASTM) 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 the unfiltered air inleakage values assumed by the licensee in its EPU dose analyses 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 above BVPS-1 and 2 CR unfiltered air inleakage values and CREVS filter efficiencies were previously accepted by the NRC in Amendment Nos. 257 and 139.

2.9.7 Atmospheric Dispersion

As stated previously in this SE, the NRC approved the LOCA and CREA radiological consequence analyses with Amendment Nos. 257 and 139 for BVPS-1 and 2, respectively. The staff also approved the MSLB, SGTR, LRA, LACP, and SLB radiological consequence analyses with Amendment No. 273 for BVPS-1. Further, for the LRA, LACP, and SLB accidents, the radiological consequence analyses performed at the EPU conditions for the LRA, LACP, and SLB accidents in Amendment No. 273 bound those accidents for BVPS-2. Thus, the following summary is limited to χ/Q values associated with the FHA for the BVPS-1 and 2, and the MSLB and SGTR for BVPS-2 dose assessments discussed above.

2.9.7.1 EAB and LPZ Atmospheric Dispersion Factors (χ/Q Values)

The licensee used design basis χ/Q values that were accepted by the NRC in Amendment Nos. 257 and 139 for BVPS-1 and 2, respectively, to evaluate the impact of radiological releases resulting from the BVPS-1 and 2 FHA, and BVPS-2 MSLB and SGTR to the EAB and LPZ as addressed in this EPU LAR. The proposed EPU would cause no changes to the EAB and LPZ χ/Q values previously reviewed and accepted by the NRC staff and, therefore, the staff finds that the EAB and LPZ χ/Q values used for this EPU LAR are acceptable. For completeness, these χ/Q values are shown in Tables 2, 3, and 4 of this SE.

2.9.7.2 Control Room Atmospheric Dispersion Factors

The licensee considered a combination of previously and newly generated control room χ/Q values in the BVPS-1 and 2 FHA, and BVPS-2 MSLB and SGTR CR dose assessments. All χ/Q values were based upon the same onsite meteorological data base and calculation methodology. Control room χ/Q values were calculated using the NRC-sponsored ARCON96 computer code (NUREG/CR-6331, Revision 1, "Atmospheric Relative Concentrations in Building Wakes") and in a manner consistent with 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. The meteorological data, methodology, and previously approved χ/Q values are discussed in the SEs associated with BVPS-1 Amendment Nos. 257 and 273 and BVPS-2 Amendment No. 139.

Based upon the meteorological measurements program and meteorological database review described in the SE associated with BVPS-1 and 2 Amendment Nos. 257 and 139, respectively, the NRC staff concludes that the 1990–1994 site meteorological database provides an acceptable basis for making atmospheric dispersion estimates for this EPU LAR. For the BVPS-1 and 2 CR FHA assessments, the licensee considered multiple combinations of release location and intake pairs and selected the most limiting case for each of the units from among all potential release locations for each unit (i.e., equipment hatch, personnel hatch, ventilation vent, containment top, containment edge). Releases from the BVPS-1 and 2 ventilation vents were determined to result in the limiting χ/Q values for the FHA. Postulated releases from the containment edge were assumed to be area sources. Initial sigma y and sigma z values were calculated by dividing the containment height and width, respectively, by a factor of six. Releases from the equipment hatch, ventilation vent, containment top, and from the MSSVs/ADVs and main steam line break point for the MSLB and SGTR accidents were modeled as point source releases. Releases through the personnel hatch were modeled to enter the environment via the ventilation vent and containment top release locations. The staff qualitatively reviewed the inputs to the ARCON96 calculations and found them consistent with site configuration drawings and the staff practice. In addition, the staff performed independent calculations of selected release point and receptor combinations by running the ARCON96 computer code and obtained similar results.

For the reasons cited above, the NRC staff concludes that the control room χ/Q values used by the licensee for the BVPS-1 and 2 FHA, MSLB and SGTR dose assessments are acceptable. These χ/Q values are shown in Tables 2, 3, and 4 of this SE.

2.9.8 Technical Specification Changes

2.9.8.1 BVPS-1 TS Limiting Condition for Operation 3.4.8, “Reactor Coolant System - Specific Activity”

The proposed change would increase the reactor coolant iodine specific activity limit from 0.1 micro curies per gram (μCi/gm) to 0.35 μCi/gm Dose Equivalent Iodine-131 for BVPS-1 only, to reflect the RSGs. The licensee had previously reduced the reactor coolant iodine specific activity limit from 0.35 μCi/gm to 0.1 μCi/gm Dose Equivalent Iodine-131 in order to accommodate the ARC and the associated accident induced leakage. With the BVPS-1 RSGs, the ARC methodology is not used, and the accident induced leakage of 14.5 gpm is no longer required. The proposed changes will make the BVPS-1 reactor coolant iodine specific activity limit consistent with that of the BVPS-2. Based on the findings of the radiological consequence analysis for the MSLB accident in Amendment No. 273, the NRC staff finds that the proposed TS change is acceptable.

2.9.8.2 BVPS-1 TS Limiting Condition for Operation 3.7.1.4, “Plant System - Activity”

The proposed change would increase the secondary coolant iodine specific activity limit from 0.05 μCi/gm to 0.1 μCi/gm Dose Equivalent Iodine-131 for BVPS-1 only to reflect the RSGs. This proposed change is the result of, and is consistent with TS changes to TS Section 3.4.8

above. Based on the findings of the radiological consequence analysis for the MSLB accident in Amendment No. 273, the NRC staff finds that the proposed TS change is also acceptable.

Conclusion

The NRC staff evaluated the radiological consequences of affected DBAs for the proposed EPU, as proposed by the licensee against the dose criteria specified in 10 CFR 50.67. These criteria are 25 Rem TEDE at the EAB for any 2-hour period following the onset of the postulated fission product release, 25 Rem TEDE at the outer boundary of the LPZ, and 5 Rem TEDE in the CR. 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 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, SRP Section 15.0.1, and GDC 19. The licensee proposed no deviation or departure from the guidance provided in RG 1.183.

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 DBAs listed in Section 2.9 above with full implementation of an AST at BVPS-1 and 2. The staff finds that the licensee used analysis methods and assumptions consistent with the conservative regulatory requirements and guidance and that the licensee has adequately accounted for the effects of the proposed EPU on these analyses. The staff also finds, with reasonable assurance, that the licensee's estimates of the EAB, LPZ, and CR doses will comply with these criteria. The staff further finds reasonable assurance that BVPS-1 and 2, as modified by these license amendments, 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 staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of DBAs.

This licensing action is considered a full implementation of the AST. With this approval, the previous accident source term in the BVPS-1 and 2 design basis is superseded by the AST proposed by the licensee. With the exception of the WGSR event, the previous offsite and CR 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. Excepting the WGSR event as addressed in Section 2.9.5 above, 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 in the BVPS-1 and 2 design basis and as modified by these license amendments.

Table 1
Radiological Consequences Expressed in Rem as TEDE [1]
For BVPS- 2

Design-basis accidents	EAB [2]	LPZ [3]	Control Room
Main steamline break accident [4]	4.0E-1	1.0E-1	2.0E-1
Dose criteria	25	25	5.0
Main steamline break accident [5]	2.5	7.0E-1	6.0E-1
Dose criteria	2.5	2.5	5.0
Steam generator tube rupture [4]	1.3	7.0E-2	3.2E-1
Dose criteria	25	25	5.0
Steam generator tube rupture [5]	6.8E-1	5.0E-2	1.3E-1
Dose criteria	2.5	2.5	5.0
Fuel handling accident [6]	2.02	0.12	2.36
Fuel handling accident [7]	2.43	0.12	1.4
Dose criteria	6.3	6.3	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
(6) For BVPS-1
(7) For BVPS-2

Table 2
Parameters and Assumptions Used in
Radiological Consequence Calculations
Main Steam Line Break Accident
For BVPS- 2

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, hours	4
Primary-to-secondary leakage	
Intact SG	150 gallons per day (gpd) (TS limit)
Ruptured SG	150 gpd plus 2.1 gallon per minute (accident-induced leakage)
Duration, hours	
Ruptured SG	21
Intact SG	8
Liquid masses, lbm	
RCS	3.41E+5
SG (each)	1.05E+5
Steam release from intact SGs, lbm	
0 to 2 hours	3.5E+5
2 to 8 hours	7.3E+5
Steam iodine partition coefficient in SGs	
Ruptured SG	1.0
Intact SG	100
Release points	
Ruptured SG	Break point
Intact SG	ADVs and MSSVs
Atmospheric dispersion values (sec/m^3)	
Exclusion area boundary	
0 to 2 hours	1.25E-3
Low population zone	
0 to 8 hours	6.04E-5
8 to 24 hours	4.33E-5
Control room	

	MSSVs/ADVs	Break Point
0 to 2 hours	5.01E-4	1.03E-3
2 to 8 hours	3.58E-4	7.84E-4
8 to 24 hours	1.61E-4	3.57E-4

Table 3
Parameters and Assumptions Used in Radiological Consequence Calculations Steam Generator Tube Rupture Accident For BVPS- 2

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, hours	4
Primary-to-secondary leakage per SG, gpd	150
Duration, hours	8
Liquid masses, lbm	
RCS	3.68E+5
SG (initial mass per SG)	9.51E+4
Steam release from ruptured SG, lbm	
116 to 3932 seconds	7.42E+4 lbm
3932 seconds to 2 hours	0
2 to 8 hours	4.36 E+4 lbm
Steam release from intact SGs, lbm	
116 to 3932 seconds	1.72E+5 lbm
3932 seconds to 2 hours	2.30E+5 lbm
2 to 8 hours	7.76E+5 lbm
Steam iodine partition coefficient in SGs	
Ruptured SG	1.0*
Unaffected SG	100
Release points	MSSVs and ADVs
Atmospheric dispersion values (sec/m^3)	
Exclusion area boundary	
0 to 2 hours	1.25E-3
Low population zone	
0 to 8 hours	6.04E-5

Control room	
0 to 2 hours	5.01E-4
2 to 8 hours	3.58E-4

*Note: The partition coefficient of 1.0 is applied only to the flashed portion of the break flow, A partition coefficient of 100 is applied to the unflashed portion of the break flow.

Table 4
Parameters and Assumptions Used in Radiological Consequence Calculations Fuel Handling Accident For BVPS-1 and 2

Parameter	Value	
Power level, MWt	2918	
Peaking factor	1.75	
Number of fuel rods in fuel assemblies	264	
Total number of fuel assemblies	157	
Number of fuel rods damaged	137	
Reactor shutdown time before fuel movement, hr	100	
Core fractions released from damaged rods		
I-131	0.12	
Other halogens	0.05	
Kr-85	0.14	
Other noble gases	0.05	
Alkali metals	0.12	
Iodine effective pool decontamination factor	200	
Duration of release	Instantaneous	
Atmospheric dispersion values (sec/m^3)		
Exclusion area boundary		
0 to 2 hours	1.25E-3 (BVPS-1)/1.04E-3 (BVPS-2)	
Low population zone		
0 to 8 hours	6.04E-5	
Control room		
	BVPS-1	BVPS-2
0 to 2 hours	4.75E-3	9.39E-4
2 to 8 hours	3.66E-3	6.69E-4

Release points	
BVPS-1	BVPS-1 ventilation vent
BVPS-2	BVPS-2 ventilation vent

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

Regulatory Evaluation

In accordance with NRC regulations, applicants for an EPU must address issues regarding the impact of the EPU on the radiation dose to members of the public and to plant employees due to the release of radioactive gaseous and liquid effluents.

Specifically, 10 CFR 20.1302 requires that gaseous and liquid effluents not exceed specified values of Appendix B to 10 CFR Part 20. Pursuant to 10 CFR 20.1301, dose from a licensed operation shall not exceed 0.1 Rem in a year to an individual member of the public, also 40 CFR Part 190 requires that dose to a member of the public due to direct shine from the uranium fuel cycle shall be limited to 25 mRem in a year. The as low as is reasonably achievable (ALARA) criteria in 10 CFR 20.1101 and Appendix I to 10 CFR Part 50, involves the evaluation of doses to members of the public from radioactive gaseous and liquid effluents. The NRC staff finds that the applicant correctly identified the applicable regulations.

Technical Evaluation

The evaluation focused on the impact of EPU for BVPS-1 and 2 from the radioactive gaseous and liquid effluent releases to members of the public and occupational worker dose, during normal operating conditions.

2.10.1.1 Gaseous and Liquid Radiological Effluent to the Public.

The NRC staff has reviewed the licensee's plan for power uprate with respect to its effect on radioactive gaseous and liquid radiological effluent releases and direct shine to the public. The licensee's assessment takes into consideration that following EPU, the operation and layout/arrangement of plant radioactive systems will remain consistent with the original design. The EPU assessment takes into account that normal operational dose rates and dose to members of the public and to plant workers must continue to meet the requirements of 10 CFR Part 20 and radioactive effluent release license conditions.

The licensee used data from the BVPS-1 and 2 Annual Radioactive Effluent Release Reports (1997 through 2001) and scaled it up to the EPU projected data to demonstrate that the projected radioactive gaseous and liquid effluent releases from the site are expected to be well within the radiological requirements contained in 10 CFR Part 20, Appendix I to 10 CFR Part 50, and 40 CFR Part 190.

The EPU will increase the radioactive liquid effluent release concentrations by approximately 14 percent. This activity is based on the long-term RCS and secondary side activity. Tritium releases in liquid effluents are expected to increase in proportion to their increased production, which is directly related to core power.

Gaseous releases of Kr-85 will increase by approximately the percentage of power increase. Isotopes with shorter half-lives will have varying EPU increase percentages up to a maximum of 18 percent. The impact of the EPU on iodine releases is slightly greater than the percentage increase in power level. Tritium releases in the gaseous effluents increase in proportion to their increased production, which is directly related to core power.

To bound the estimated impact of EPU on the annual offsite releases, the licensee used the highest percentage change in activity levels of short-lived (t ½ < 8 days) and long lived isotopes in each chemical grouping found in the primary reactor coolant and secondary fluids that characterize each unit. The licensee then applied the values to the applicable gaseous and liquid effluent pathways. The percentage change was applied to the doses reported in the licensee's radioactive effluent reports for 1997 through 2001 (adjusted to reflect a 100 percent capacity factor) to calculate the offsite doses following EPU. The licensee concluded that although the doses increased, they were below the regulatory requirements of 10 CFR Part 20 and Appendix I to 10 CFR Part 50.

In addition to the dose impact to radioactive gaseous and liquid effluents, the licensee evaluated the dose impact of the EPU on the direct radiation (skyshine) from plant systems and components containing radioactive material to members of the public, as required by 40 CFR Part 190. The licensee's evaluation concluded that the direct radiation doses are not expected to increase significantly over current levels and are expected to remain within the limits of 40 CFR Part 190.

2.10.1.2 Personnel Exposure

The NRC staff has evaluated the licensee's plan regarding occupational exposure related to the EPU. The licensee has evaluated the impact of the EPU on the radiation source terms in the reactor core, irradiated fuels/objects, RCS and downstream radioactive systems. These source terms are expected to increase by approximately 7.9 percent after a core power uprate from 2689 MWt to 2900 MWt. The radiation exposure received by plant personnel is expected to increase by approximately the same percentage. The above increase in radiation levels will not affect the radiation zoning or shielding requirements in the various areas of the plant because the increase due to EPU will be offset by the conservatism in the pre-EPU "design-basis" source terms used to establish the radiation zones, plant TSs that limit the RCS concentrations to levels well below the design-basis source terms, and conservative analytical techniques used to establish shielding requirements. Regardless, individual worker exposures will be maintained within acceptable limits by the site Radiation Protection Program which controls access to radiation areas. In addition, procedural controls and ALARA techniques are used to limit doses in areas having increased radiation levels.

Conclusion

On the basis of our review of the BVPS-1 and 2 EPU LAR, the NRC staff concludes that the proposed 8-percent power uprate will not have a significant effect on occupational dose or on

the dose to members of the public from radioactive gaseous and liquid effluent releases and doses due to direct shine. The licensee has programs and procedures in place to ensure that radiation doses are maintained ALARA in accordance with the requirements of 10 CFR 20.1101, Appendix I to 10 CFR Part 50, and 40 CFR Part 190. The staff, therefore, finds the proposed power EPU at BVPS 1 and 2 to be acceptable from a normal operations health physics perspective.

2.11 Human Performance

Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The NRC staff's human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system changes made to implement the proposed EPU. The staff's review covered changes to operator actions, human-system interfaces, procedures and training needed for the proposed EPU. The NRC's acceptance criteria for human factors are based on the following documents: GDC 19; 10 CFR 50.120; 10 CFR Part 55; ANSI/ANS Standard 58.8 (1994/2001), "Time Response Design Criteria for Safety-Related Operator Actions," and the guidance in GL 82-33. Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and Chapter 18.0.

Technical Evaluation

The NRC staff has developed a standard set of questions for the review of the human factors area. The licensee has addressed these questions in its application, in its response to the staff's RAI and in telephone conferences held on August 4, 2005 and January 9, 2006. The following are the staff's questions, the licensee's responses, and the staff's evaluation of the responses.

1. Changes in Emergency and Abnormal Operating Procedures

This section evaluates how the proposed EPU will change the plant emergency and abnormal operating procedures. (SRP Section 13.5.2.1)

In its submittal, the licensee stated the EPU will require a revision of operating procedures including EOPs, the abnormal operating procedures (AOPs), and the severe accident management guidelines (SAMGs). All operating procedures affected by the EPU LAR will be revised using the existing procedure revision processes and issued for use at the time of implementation. The changes include minor modifications required for some parameter thresholds and graphs which depend on the power and decay heat levels as well as changes in setpoints. A summary of the non-setpoint changes to operation procedures are as follows:

- Operation at higher RTP level (i.e., revised RCS temperatures, revised steam and feed flows, temperatures, and pressures, revised feedwater and heater drain flow control valve positions, and revised electrical loads)

- Revised operating band for SI accumulator pressure and level

- Revised SI flows used in safety analysis (revised minimum pump curve)
- Revised AFW flows used in safety analysis (revised minimum pump curve)
- Revised maximum RWST temperature
- Revised decay heat curve
- Revised main generator capability curve and volts amps reactive (VAR) loading
- Revised primary and secondary activity TSs (BVPS-1 only)
- Revised RCP seal injection TS surveillance

The licensee will update affected setpoints in operating procedures, including EOPs, AOPs and SAMGs, to new uprate values. A specific, non-setpoint, change will be the elimination or revision of procedures that contain steps that fulfill surveillances for the BVPS-1 boron injection tank (BIT) TSs to reflect the elimination of the associated TS requirements.

Overall, the licensee indicated that the operating procedure changes due to the EPU do not result in significant changes in the operating philosophy or the accident mitigation philosophy. In addition, the licensee committed to providing training to cover procedure changes related to the EPU prior to implementation. Therefore, because no significant changes to operating/accident management philosophy are required, necessary changes to EOPs/AOPs/SAMGs setpoints will be implemented, and training to address these changes will be provided, the NRC staff finds the licensee's proposed changes in this area to be acceptable.

2. Changes to Operator Actions Sensitive to Power Uprate

This section evaluates any new operator actions needed as a result of the proposed EPU and changes to any current operator actions related to emergency or abnormal operating procedures that will occur as a result of the proposed EPU. (SRP Section 18.0)

The licensee identified one new operator action relating to the EOPs as a result of the proposed EPU. The new action is as follows:

> Initiate a control room purge after a steam generator tube rupture (SGTR) - within 8 hours following termination of the environmental release for a SGTR, the control room is purged for 30 minutes at 16,200 cubic feet per minute (cfm).

The design basis of the control CR emergency habitability system purge function ensures the capability to manually purge the air from the CR for selected DBAs, to ensure acceptable dose consequences to the CR personnel following a DBA.

The licensee identified changes to operator actions relating to the EOPs and to operator action times as a result of the proposed EPU analysis. The licensee stated that the operator's ability to perform the functions required does not change due to the EPU. The following required operator action times were decreased due to the EPU:

- initiate switchover to simultaneous or alternating hot leg/cold leg recirculation (BVPS-1 and 2)
- isolate AFW to the ruptured SG (BVPS-2)
- initiate cooldown from the intact SG via the main steam system after MSIV closure (BVPS-2)

In response to RAIs, the licensee provided detailed tables including the operator action description, the operator action time used previously in current power analysis, the operator action time used in the EPU analysis and the time it takes for the operator to perform the action. Some of the operator action times used in the licensee's EPU analysis were more restrictive with respect to the margin between the time available for the operator to perform the required actions and the time it actually will take for the operator to perform these actions. The following table displays the most restrictive operator action time margins for both units:

Table 2.1
Summary of Restrictive Operator Action Times Data

Operator Action	Time Available/ Times used in EPU analysis	Action Performance Time	Time Used in current analysis
BVPS-1			
terminate high-head SI flow to the RCS	within 10 minutes of the start of the event	9.7 minutes	No time for this action used in the current analysis
BVPS-2			
isolate AFW flow to the ruptured SG	within 5.5 minutes after reactor trip	5.0 minutes	within 9.1 minutes after reactor trip
initiate cooldown from the intact SGs via the main steam system after MSIV closure	within 2.0 minutes after the MSIV is closed for actions inside the main CR	2.0 minutes	No time for this action used in the current analysis
	within 7.0 minutes after the MSIV is closed for actions outside the main CR	6.0 minutes	within 9.0 minutes after the MSIV is closed for actions outside the CR

The NRC staff was concerned regarding the relatively short 2-minute action for the operators to initiate a cooldown following isolation of the ruptured SG for BVPS-2. However, the action is the same as before, namely to initiate bleeding steam from the atmospheric steam dump valve.

The licensee has asserted that this action can be reliably performed within this time available. This was determined to be acceptable provided that the licensee validates the performance time in BVPS-2 simulator prior to implementing the power uprate.

The BVPS-1 operator action times for EPU conditions have been validated for revised EOPs and confirmed on the BVPS-1 simulator for CR actions as part of the EOP review process. Actions outside the CR were validated by a step by step walk-through in the plant of the draft EOP being validated as part of the procedural change process. Though one of the operator action times is more restrictive than the other times used in the analysis for BVPS-1, the validation conducted by the licensee concluded that the operator action could be performed in the time available in EPU conditions for BVPS-1.

The revisions to BVPS-2 EOPs have not been completed at this time. The BVPS-2 response times for EPU conditions were confirmed by operator talk-throughs or walk-throughs using senior licensed operators (SROs) who are currently licensed at BVPS-2. The talk-throughs consisted of the review team reading and evaluating the understandability of the steps, notes or cautions in the EOPs. Input was also received from the operations management team on the talk-through times at BVPS-2. The NRC staff was concerned with the restrictive margins listed in Table 2.1 for BVPS-2, because the operator action times for actions inside the CR have not been validated on a unit-specific simulator that has been updated for EPU conditions. The licensee has committed to validating the operator action times obtained through the talk-through process for BVPS-2 as part of the procedural change process. The staff finds the operator action times submitted by the licensee acceptable and the licensee's commitment to validating the BVPS-2 operator action times as part of the procedural change process (commitment no. 11 in Section 4.0 of this SE) acceptable.

Based on the licensee's description of the types of actions required, the time available, operator action time validations for BVPS-1, and the commitment to validate operator action times for BVPS-2, the licensee has provided the NRC staff with reasonable assurance that operators will be able to successfully accomplish the new task of purging the CR after an SGTR and other procedural operator action changes required to support the proposed EPU. Regarding the operator actions with reduced time limits, the validity of the screening process and calculations used by the licensee are discussed by another section of the safety analysis.

3. Changes to Control Room Controls, Displays and Alarms

This section evaluates any changes the proposed EPU will have on the operator interfaces for CR controls, displays, and alarms. (SRP Section 18.0)

The licensee stated the instrumentation will be re-normalized such that 100 percent indications of RTP will remain at 100 percent RTP. Operator interfaces for CR controls, displays, and alarms will be re-normalized such that there are no changes in operator actions for normalized protection, control, displays, and alarms. BVPS-1 does not use zone markings on any meters. The licensee identified no controls, displays, or alarms that will be upgraded from analog to digital as a result of the proposed EPU.

The licensee provided a summary of functions being revised as a result of the EPU analyses. The engineering change process (ECP) requires that the training department perform a

systematic approach to training (SAT) evaluation for all affected plant modifications. If the SAT evaluation determines that training is to be performed, then the applicable training material lesson plans will be revised to address the plant modifications. The designated personnel, as

determined by the Operations Training Committee, will complete training on the applicable changes prior to implementation.

The purpose of this section is to assure that the licensee has adequately considered the equipment changes resulting from the EPU that affect operator ability to perform required functions. Based on the licensee's response, the NRC staff is satisfied that the licensee appropriately identified the necessary changes.

4. Changes to the Safety Parameter Display System (SPDS)

This section assesses any changes to the SPDS resulting from the proposed EPU, and how the operators will be made aware of the changes. (SRP Section 18.0)

As described in the previous section, the plant process instrumentation will be normalized to the uprated power levels. The instrument spans and setpoints both require changes on the SPDS for BVPS-1 and the emergency response facility computer system (ERFCS), which is equivalent to an SPDS, for BVPS-2. Both the BVPS-1 SPDS equipment and the BVPS-2 ERFCS are available in both the CR and the emergency response facility (ERF). For both units, the feedwater and main steam flow transmitters are being replaced with units capable of measuring larger differential pressures. Instrument loop scaling remains within the range of the existing displays.

The plant ECP will be followed to make the changes. The planned changes to the SPDS and ERFCS are summarized by the licensee in Table 13 of its May 26, 2005, RAI response in support of the EPU LAR. The changes listed in Table 13 of the licensee's May 26, 2005, RAI response accurately reflect physical plant changes as a result of the EPU and are therefore, acceptable. The licensee will make changes to the systems in each unit and training the designated personnel on the applicable changes to the SPDS and the ERFCS prior to startup at the modified conditions.

5. Changes to the Operator Training Program and the Control Room Simulator

This section evaluates any changes to the operator training program and the plant-referenced control room simulator necessary to support the proposed EPU as well as the implementation schedule for making the changes (SRP Sections 13.2.1 and 13.2.2).

The licensee stated that the ECP requires the training department to perform an evaluation per the SAT for all affected plant modifications, procedural changes, and operator action times. All of the changes for the EPU will be implemented by an ECP. The designated licensed and non-licensed personnel will receive training on the changes prior to implementation.

The BVPS-1 and 2 unit-specific simulators accurately reflect the plant status, physical appearance (hardware) and simulation of plant response (software), changes resulting from the EPU that affect the CR will also be made to the simulators and implemented through approved plant change processes.

The BVPS-1 simulator SG model is being revised for the RSG configuration, and associated changes to the BVPS-1 simulator were implemented during the spring 2006 1R17 refueling outage. Changes that affected the simulator were implemented through the approved plant change process. The setpoint and scaling changes for BVPS-1 were performed for the EPU, RSG, and containment conversion changes to support EOP validations. BVPS-2 is not replacing its SGs so these changes do not apply to the BVPS-2 simulator. BVPS-2 scaling and setpoint changes for the EPU and containment conversion will also be performed to support EOP validations prior to plant implementation.

Both BVPS-1 and 2 simulators will be bench-marked with the best-estimate engineering models for the 10 ANSI/ANS-3.5 Appendix B transients and will have an initial 100 percent steady-state comparison to the predicted values followed by a final comparison to actual plant values at 100 percent power. Both BVPS simulators are currently certified to the ANSI/ANS-3.5-1985 standard.

The NRC staff is satisfied that, based on the above commitments, the licensee will develop and implement a satisfactory training program, including simulator training for the proposed EPU.

Conclusion

The NRC staff has reviewed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that the licensee has (1) appropriately accounted for the effects of the proposed EPU on the available time for operator actions and (2) taken appropriate actions to ensure that operator performance will not be adversely affected by the proposed EPU. The staff further concludes that the proposed changes will continue to meet the requirements of GDC 19, 10 CFR 50.120, and 10 CFR Part 55 following implementation of the proposed EPU. Therefore, the staff finds the licensee's proposed EPU acceptable with respect to the human factors aspects of the required system changes.

2.12 Power Ascension and Testing Plan

Regulatory Evaluation

The purpose of the EPU test program is to verify that SSCs will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The NRC staff's review included an evaluation of: (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance; (2) integrated plant systems testing, including transient testing, if necessary, to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level; and (3) the test program's conformance with applicable regulations. The NRC's acceptance criteria for the proposed EPU test program was based, in part, on: (1) 10 CFR Part 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service; (2) GDC 1, "Quality standards and records," of Appendix A to 10 CFR Part 50, insofar as it requires that SSCs important to safety be tested to quality standards commensurate with the importance of the safety functions to be performed; (3) 10 CFR Part 50.34, "Contents of applications: technical information," which specifies requirements for the content of the original operating license application including

Final Safety Analysis Report (FSAR) plans for pre-operational testing and initial operations; and (4) RG 1.68, Appendix A, Section 5, "Power Ascension Tests," which describes tests that demonstrate that the facility operates in accordance with design both during normal steady-state conditions, and, to the extent practical, during and following AOOs. Specific review and acceptance criteria are contained in SRP Section 14.2.1.

Technical Evaluation

1. SRP Section 14.2.1, Section III.A. - Comparison of Proposed Test Program to the Initial Plant Test Program

Evaluation Criteria

SRP Section 14.2.1, Section III.A. specifies the guidance and acceptance criteria which the licensee should use to compare the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison should include (1) all initial power-ascension tests performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level, and (2) initial test program tests performed at lower power levels if the EPU would invalidate the test results. The licensee should either repeat initial power-ascension tests within the scope of this comparison or adequately justify proposed deviations from the initial power-ascension test program. The following specific criteria should be identified in the EPU test program:

- all power-ascension tests initially performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level,

- all initial test program tests performed at power levels lower than 80 percent of the original licensed thermal power level that would be invalidated by the EPU, and

- differences between the proposed EPU power-ascension test program and the portions of the initial test program identified by the previous criteria.

NRC Staff's Evaluation

The NRC staff found that Section 14.2.1 of the BVPS-2 UFSAR committed to a startup test program structured in compliance with RG 1.68, "Initial Test Program for Water-Cooled Reactor Power Plants," and the applicable regulatory guidance regarding the qualification of startup testing personnel for the original program, i.e., RG 1.58, "Qualification of Nuclear Power Plants Inspection, Examination, and Testing Personnel." The minimum qualifications of supervisory personnel involved in the pre-operational and initial start-up test phases (for safety-related tests only) were in accordance with RG 1.8, "Personnel Selection and Training." Similarly, Section 13.0 of the BVPS-1 UFSAR provides a description of the applicable guidance used by the applicant to determine which tests were applicable for the plant. The guidance included "Guide for the Planning of pre-operational Testing Programs", United States Atomic Energy Commission (USAEC), December 7, 1970, and "Guide for the Planning of Initial Startup Programs", USAEC, December 7, 1970 (revised). Personnel performing the tests will be part of the startup and operation organization and will be qualified by experience and training to perform these activities as stated in UFSAR Section 13.2. These personnel will be under the

supervision of the BVPS-1 Superintendent, Licensed Senior Operators and the Technical Supervisor. Section 13.2 states that all operating personnel will be qualified, trained and appropriately licensed as prescribed by law. Supervision will be by licensed SROs and reactor operations will be performed by licensed reactor operators. Senior management and technical support personnel have been assigned on the basis of prior reactor plant operating and test experience and training. In most cases, these persons are licensed or have been previously certified in reactor operation. The staff found that those commitments were also part of the proposed EPU test plan.

The NRC staff reviewed the following EPU test plan information provided by the licensee in order to verify that the initial EPU license amendment submittal, supplemental information provided in response to staff RAIs, and applicable sections of TSs and the FSAR addressed the specific criteria for an adequate EPU test program as described above. Specifically, the following documents were reviewed during the staff's evaluation:

- BVPS -1 UFSAR Section 13, "Initial Tests and Operation" - Provided an overview of the initial power ascension test program from initial fuel loading through 100 percent power.

- BVPS -2 UFSAR Section 14, "Initial Test Program" - Provided a detailed description of the regulatory basis for the program, the initial startup test program, and the overall test objectives, methods, and acceptance criteria.

- BVPS Units 1 and 2, "Extended Power Uprate License Amendment Request," dated October 4, 2004, EPULR, Section 13, "Testing" - Described an overview of the test program for the approach to the EPU power level.

- Attachment D, Table 1, of FENOC letter L-04-026, dated February 23, 2005, "EPU Modifications and Testing" - Provided a description of planned EPU modifications, affected system(s), and proposed post-modification test plans.

- Attachment D, Table 2, of FENOC letter L-04-026, dated February 23, 2005, "EPU Parameter and Setpoint Changes" - Provided a description of the parameter and setpoint changes, uprate impact, justification and proposed testing.

- Attachment D, Table 3, of FENOC letter L-04-026, dated February 23, 2005, "EPU Test Plan" - Provided the EPU related tests and the power level at which the tests will be performed during power ascension.

- Attachment D, Table 4, of FENOC letter L-04-026, dated February 23, 2005, "Comparison of Original Power Ascension Testing to the Planned Extended Power Uprate Testing" - Provided the original tests, the associated Startup Test Report section, and an evaluation of the tests as related to the proposed EPU test program including the rationale for performing or not performing a test as part of the EPU.

- Attachment D, Table 5, of FENOC letter L-04-026, dated February 23, 2005, "BVPS-1 Comparison of Original Power Ascension Testing to the Planned Extended Power Uprate Testing" - Provided the original tests, the associated UFSAR reference, and the rationale for performing or not performing a test as part of the EPU.

- Attachment D, Table 6, of FENOC letter L-04-026, dated February 23, 2005, "BVPS-2 Comparison of Original Power Ascension Testing to the Planned Extended Power Uprate Testing" - Provided the original tests, the associated Startup Report reference, and the rationale for performing or not performing a test as part of the EPU.

- Attachment D, Table 7, of FENOC letter L-04-026, dated February 23, 2005, "BVPS-2 Comparison of Original Power Ascension Testing to the Planned Extended Power Uprate Testing" - Provided the original tests, the associated UFSAR reference, and the rationale for performing or not performing a test as part of the EPU.

- FENOC letter L-06-035, dated March 10, 2006, "BVPS Units 1 and 2, Supplemental Information - EPU Implementation Plan & Power Ascension Testing: License Amendment Request Nos. 302 and 173" - Provided an updated power ascension and testing program schedule and updated commitments with respect to modifications and testing necessary to support the EPU.

The applicant reviewed the applicable UFSAR sections and the initial startup test reports and supplements for BVPS-1 and 2 to identify all initial pre-operational and startup tests performed on BVPS-1 and 2. This list was then evaluated to determine which initial tests met the screening criteria in SRP Section 14.2.1, Section III.A. to establish the additional testing necessary for the EPU conditions. The results of this evaluation were provided to the NRC staff in the February 23, 2005, supplement to the EPU LAR. The staff reviewed and verified that all tests described in the initial startup test program, including pre-operational tests, system operational tests, and initial startup tests, were addressed in the description of the proposed EPU test program. In addition, a licensee evaluation of the initial test program found no examples of tests performed at lower than 80 percent of the original licensed thermal power level that would be invalidated by the EPU. The staff agreed with the licensee's determination in that regard.

The NRC staff also noted that the applicant committed to perform a series of tests specific to the BVPS-1 plant which were not part of the original startup tests for the site. The rationale for this was to ensure consistency in the evaluation between the two uprated units. For example, if a test was performed on the BVPS-2 unit at a power level of approximately 100 percent during initial startup testing, and that test was being re-performed on BVPS-2 for EPU, the same test would also be applied to BVPS-1. Specific examples of this include, but are not limited to, secondary system vibration frequency and amplitude, secondary system expansion and restraint, primary sampling system tests, and turbine plant system tests. The staff agrees with the licensee's approach to performing those additional tests on BVPS-1.

The NRC staff also noted the following test description differences for the proposed EPU testing as it related to the initial power ascension test program as described in UFSAR Sections 13 and 14 for BVPS-1 and 2, respectively.

Startup adjustments made to the reactor control system during steady-state operation will be monitored and data collected at power levels greater than the original licensed power; specifically at 2770 MWt, 2830 MWt, and 2900 MWt. Steady-state conditions will be established, and control systems monitored to determine if any adjustment are required to the T_{ave} program to reflect the main steam pressure at full power. RCS average temperature, RCS reference temperature, turbine first-stage pressure and thermal power data will be collected at these uprated power levels. As discussed in this SE, the NRC staff found the proposed monitoring and data collection to be in accordance with SRP Section 14.2.1.

For initial startup, a full power demonstration test was performed to demonstrate the reliability of the NSSS by maintaining the plant at or near full thermal power (95 to 100 percent) for a period of 100 hours. Primary and secondary calorimetric data was recorded and evaluated to verify the proper operation of the NSSS. Thermal power calorimetric data was taken at 100 percent power level to calculate reactor core thermal power output. Secondary plant data such as steam pressure, feedwater flow, and feedwater temperature were recorded for this calculation. For the uprated conditions, thermal power calorimetric measurements will be taken at various steady-state conditions up to current rated power levels, and continue at EPU RTP levels at 2770 MWt, 2830 MWt, and 2900 MWt to record reactor core thermal power output. As discussed in this safety evaluation, the NRC staff found the proposed monitoring and data collection to be in accordance with SRP Section 14.2.1.

The NRC staff also reviewed information contained in the EPU LAR, supplemental information, and the UFSAR, regarding low power physics testing and RCS thermal power determination calculations. The staff found that the low power physics testing, as described in UFSAR Sections 13.1 and 14.2, respectively, consisted of a series of tests performed after the reactor was taken critical and sustained critical operation without producing measurable nuclear heat. The test then compared measured results to predicted values. These values will remain unchanged for the EPU, however, the test will continue to be performed at each core reload, including the reload associated with the EPU, in accordance with TS requirements.

Conclusion

The NRC staff concludes, through comparison of the documents referenced above and a review of test commitments referenced in the UFSAR, that the proposed EPU test program adequately identified: (1) all initial power ascension tests performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level; and (2) differences between the proposed EPU power-ascension test program and the portions of the initial test program identified by the previous criteria. Additionally, the staff agrees with the licensee evaluation that found no examples of tests performed at lower than 80 percent of the original licensed thermal power level that would be invalidated by the EPU. The staff also concludes that in determining EPU test requirements, the licensee had adequately evaluated the need for any additional low power physics testing and RCS thermal power determination calculations.

2. SRP Section 14.2.1 Section III.B.- Post Modification Testing Requirements for SSCs Important to Safety Impacted by EPU-Related Plant Modifications

Evaluation Criteria

SRP Section 14.2.1, Section III.B. specifies the guidance and acceptance criteria which the licensee should use to assess the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to AOOs. AOOs include those conditions of normal operation that are expected to occur one or more times during the life of the plant and include events such as LOOP, tripping of the main turbine generator set, and loss of power to all RCPs. The EPU test program should adequately demonstrate the performance of SSCs important to safety that meet all of the following criteria: (1) the performance of the SSC is impacted by EPU-related modifications; (2) the SSC is used to mitigate an anticipated operational occurrence described in the plant-specific design basis; and (3) involves the integrated response of multiple SSCs. The following should be identified in the EPU test program as it pertains to the above paragraph:

- plant modifications and setpoint adjustments necessary to support operation at power uprate conditions, and
- changes in plant operating parameters (such as reactor coolant temperature, pressure, T_{ave}, reactor pressure, flow, etc.) resulting from operation at EPU conditions.

NRC Staff's Evaluation

The NRC staff reviewed the planned EPU modifications and their potential effect on SSCs as documented in the applicant's letters dated February 23, 2005 and March 10, 2006, containing supplemental information in support of the EPU LAR. The post-modification tests listed in Table 1 of the February 23, 2005, letter were the acceptance tests to demonstrate design function performance and integration with the existing plant. The staff also reviewed the basis for the licensee's conclusions that the modifications did not change the design function of the SSCs or the methods of performing or controlling their functions, as described in the February 23, 2005, submittal and accompanying table. As part of the implementation of the modifications to support EPU, the applicant shall construct, install, and pre-operationally test each modification in accordance with the normal plant design process procedures. The tests described for the EPU are the final acceptance tests that will demonstrate that the modifications will perform their design functions and integrate appropriately with the existing plant. The following modifications and post-modification test (PMT) descriptions were reviewed by the staff.

- Reactor Control and Protection System - For Unit 1, modifications to the over temperature delta temperature (OT ΔT) and over power delta temperature (OP ΔT) equations require the installation of lead/lag filter cards to restore original design capability. Modifications reduced steam generator low-low level reactor trip and auxiliary feedwater (AFW) actuation and raised steam generator high-high level turbine trip and feed water (FW) isolation setpoints. For Both Unit 1 and Unit 2, constants used to calculate OT ΔT and OP ΔT trip set points are being changed to

optimize operating margins at EPU conditions. The PMT will consist of a TS calibration and surveillance testing.

- Plant Control Systems and Instrumentation - For both units, scaling changes for various parameters including reactor coolant flow and temperature, T_{ref}, rod control, pressurizer level control and balance of plant instrumentation and controls instruments. Setpoint changes for the reactor water storage tank temperature high alarm set point, safety injection accumulator level and pressure, steam dump control, and steam generator level control. Additionally replacement of main steam and feedwater system instruments to account for increased flow rates, and replacement of steam generator narrow range level instruments to account for increased span are being implemented. The changes were required to ensure that under EPU conditions, the plant would be maintained within normal operating bands during normal operations and would stabilize the plant during minor load changes and load rejection events. The modifications will not change the design function or method of controlling the function. The PMT will consist of a TS calibration, setpoint testing, and surveillance testing.

- Main Turbine - For both units, the high pressure turbine modification will consist of installing a new high pressure turbine rotor with all-reaction blading, changing first stage instrument setpoints and replace the first stage pressure transmitters. The PMT will measure generator output in addition to flow, pressure and temperature measurements, system vibration monitoring. Calibration and scaling of first stage pressure transmitters will be performed.

- Main Generator - For both units, a nameplate re-rating change is being implemented. This is a document change only.

- Main Transformer - For Unit 2 only, the transformer cooler will be modified to provide improved cooling capacity. The PMT will measure baseline temperature and electrical load data on the transformer and bus duct. The design function of the system will not change due to EPU modification.

- Chemical and Volume Control System - For both units, charging pump rotating elements will be replaced to increase system flow rate. Re-throttling of charging pumps will be performed to ensure balanced system flow. The PMT will consist of surveillance testing.

- Feedwater Heater Drain System - For both units, the normal and/or alternate feedwater heater level control valves and Main Steam and Main Feedwater flow transmitters will be upgraded or replaced to accept the proposed EPU operating conditions. The PMT will verify that feedwater heater levels are maintained in the normal operating band, and ensure valve seat leakage and stroke time are within design limits.

- Main Condenser - For Unit 2 only, additional main condenser tube supports will be added to minimize the effects of flow induced vibration for the proposed EPU operating conditions. The PMT will consist of monitoring secondary system vibration parameters.

- Moisture Separator Reheater - For both units, a modification to increase relief valve setpoint will be performed to increase operating margin to relief valve open set point. The PMT will be a setpoint test and capacity verification performed by the vendor prior to installation.

- Steam Generator - For Unit 1 only, the steam generator will be replaced. Various instrument tests will be performed to verify steam flows are normalized to feedwater flow rate, RCS ΔT are normalized to percent power, RCS flow rate verified at full power, High pressure first stage turbine pressure adequately controls Tref, and verification that steam generator water level control maintains level at proper set point.

The licensee stated that evaluations of the actual test results may identify the need for additional tests or revision of the tests planned, and therefore, the final test plan may be revised.

The NRC staff also reviewed the EPU modification aggregate impact analysis submitted by the licensee in the supplemental response dated February 23, 2005. The staff noted that as part of its analyses, the applicant evaluated several other similar Westinghouse designed 3-loop plants (North Anna Power Stations Units 1 and 2, Virgil C. Summer, and Shearon Harris) that are currently operating at approximately the EPU NSSS power level. The applicant reviewed both operational and analytical experience applied to the evaluation of aggregate impacts of plant modifications in support of the EPU to determine what, if any, credible impact to dynamic plant performance might exist. The applicant identified and evaluated both units for steady state operations, normal operations and operational transients (Condition I events) which do not result in reactor trips, and faults of moderate frequency (Condition II events), infrequent faults (Condition III events), and limiting faults (Condition IV events) which involve the potential for reactor trips and ESF features actuation. Where a potential aggregate impact was identified, the modification was modeled into the applicable EPU safety analysis or was evaluated utilizing various computer code analyses (LOFTRAN, BELOCA, and WCOBRA/TRAC). The codes had, in general, been previously used in analyses and evaluations for BVPS-1 and 2 units at current power conditions with two exceptions; (1) for the Condition IV LBLOCA where the NRC-approved Westinghouse BELOCA methodology and WCOBRA/TRAC computer code were used and, (2) for the Condition II non-LOCA transients where the NRC-approved VIPRE computer code was used. Both of these computer codes are generically NRC-approved and are being used for the first time at BVPS. These are the same computer codes that are used in the analyses of Condition II, III, and IV initiating events for other Westinghouse-designed nuclear power plants. Furthermore, analytical and operational experience at these other Westinghouse designed plants supports the use of these computer codes for assessing the aggregate impact of the EPU equipment modifications and setpoint changes in combination with the EPU operating conditions on the BVPS units. Analysis inputs and models were updated to reflect the uprated plant configurations (e.g., plant equipment modifications and setpoint changes) as well as EPU operating conditions. As described in the EPULR, the aggregate impact of the modifications would not result in a significant change to the plant's dynamic response to anticipated Condition I, II, III, or IV initiating events or normal operations. The dynamic plant responses to Condition II, III, and IV initiating events at EPU conditions with the EPU equipment modifications and setpoint changes are consistent with their characteristic responses based on operational and analytical experience on the BVPS units at the current

power conditions as well as operational and analytical experience on other similar Westinghouse-designed 3-loop nuclear power plants currently operating at approximately 2910 MWt NSSS power. The staff also verified that the licensee adequately identified functions important to safety, setpoint adjustments, and changes in plant operating parameters affected by the EPU modifications.

Conclusion

The NRC staff concludes, based on review of each planned modification, the associated post-maintenance test, and the basis for determining the appropriate test, that the EPU test program will adequately demonstrate the performance of SSCs important to safety and includes those SSCs (1) impacted by EPU-related modifications, (2) used to mitigate an AOO described in the BVPS-1 and 2 design bases, and (3) which supported a function that relied on integrated operation of multiple systems and components.

The NRC staff concludes that the proposed test program adequately identifies plant modifications and setpoint adjustments necessary to support operation at the uprated power level and changes in plant operating parameters (such as reactor coolant temperature, pressure, T_{ave}, reactor pressure, flow, etc.) resulting from operation at EPU conditions. Additionally, the staff determines that there are no unacceptable system interactions because of modifications to the plant.

3. SRP Section 14.2.1, Section III.C - Justification for Elimination of EPU Power-Ascension Tests

Evaluation Criteria

SRP Section 14.2.1, Section III.C. specifies the guidance and acceptance criteria the licensee should use to provide justification for a test program that does not include all of the power-ascension testing that would normally be considered for inclusion in the EPU test program pursuant to the review criteria of Sections 1 and 2 above. The proposed EPU test program should be sufficient to demonstrate that SSCs will perform satisfactorily in service. The following factors should be considered, as applicable, when justifying elimination of power-ascension tests:

- previous operating experience,
- introduction of new thermal-hydraulic phenomena or identified system interactions,
- plant staff familiarization with facility operation and trial use of operating and emergency operating procedures,
- margin reduction in safety analysis results for anticipated operational occurrences, and
- risk implications.

NRC Staff's Evaluation

The NRC staff reviewed information regarding the following deviations, additions, or exceptions to original startup testing contained in the licensee's supplemental information provided in a letter dated February 23, 2005.

- As noted in Section 1, "SRP Section 14.2.1, Section III.A. - Comparison of Proposed Test Program to the Initial Plant Test Program," above, the applicant is prepared to perform a series of power ascension tests on BVPS-1, which were not originally performed during the initial startup. The applicant is performing these tests to better align the testing between BVPS-1 and 2 as these plant systems are essentially identical as a result of the uprated conditions. Specific tests which will be performed on BVPS-1 as a result of this decision include, but are not limited to, secondary system vibration frequency and amplitude, secondary system expansion and restraint, component cooling system test (containment penetration cooling system and turbine plant component cooling water system), primary sampling system test, turbine plant sampling system performance test, main transformer performance test, and containment ventilation system test. Test abstracts for BVPS-1 and 2 for these tests are the same.

- In addition, the applicant has taken exception to re-performance of several BVPS-1 and 2 initial power-ascension tests, or has proposed deviations from the original ascension tests performed. The following EPU tests were reviewed by the NRC staff.

(1) BVPS-1 Turbine Control and Bypass Valve Test - a new value for full load T_{ave} and change in plant load rejection capability impact operation of the steam dump controls. These changes are scaling and setpoint changes that will be implemented and tested through the use of the plant instrument and setpoint calibration process.

(2) BVPS-1 Control Rod Position Indication System Test - the original system electronics have been replaced under the plant modification process and tested as part of that effort. PMT results are still valid for the uprated conditions.

(3) BVPS-1 Incore Thermocouple and Resistance Temperature Detector (RTD) Cross Calibration Test and Bypass Loop Flow Verification - the original RTDs and bypass manifolds were replaced by fast response RTDs. Test results associated with the PMT are still valid for the uprated conditions.

(4) BVPS-1 Reactor Coolant System Flow Measurement - the original test determined flow from RCP performance. That original test method is no longer used and the revised test method bases flow on plant calorimetric data taken during full operating power level.

(5) BVPS-1 and 2 Operational Alignment of the Nuclear Instrumentation System (NIS) - during initial power ascension the NIS was not fully tested, but at initial full power the NIS gains were properly adjusted. For the uprated conditions, the NIS system is tested as part of the maintenance and surveillance programs. At

EPU full power the NIS instrumentation normalization to calorimetric power will be verified through EPU testing.

(6) BVPS-1 and 2 Start-up Adjustments to Reactor Control - during initial power ascension testing , the full power value of T_{ref} was adjusted to obtain desired main steam pressure. For uprated conditions the value of T_{ref} is set by the design and determined by the analysis, and therefore will not be adjusted as a result of the uprate testing. For EPU the test is to verify the associated instruments are scaled and calibrated to assure that T_{ref} reaches its full power value when the plant reaches EPU rated thermal power.

(7) BVPS-1 and 2 Vibration and Loose Parts Monitoring System (LPMS) - for the BVPS-1 and 2 units, the LPMS is no longer required to be operable per the plants' licensing bases. Various features of the system have been removed, modified, or maintained only as an operational convenience. Therefore, testing on the system is not required.

(8) BVPS-1 and 2 Pressurizer Test - pressurizer level control was tested at Mode 3, no-load T_{ave} during initial testing. As a result of the EPU conditions, the T_{ave} program and the upper range of the pressurizer level control are being changed. Therefore, testing shall be performed to ensure the pressurizer level controller can maintain an appropriate level for the corresponding RCS temperature at the uprated conditions.

(9) BVPS-2 Engineered Safety Features Equipment Ventilation Tests - control building heating, ventilation, and air conditioning test, and fuel building, decontamination building, and pipe tunnel area heating, ventilation, and air conditioning system tests were surveyed at greater than 80 percent power in some cases. As a result of the EPU conditions, additional heat load to these areas could impact equipment, components, or control logic within these areas. The licensee has performed an evaluation of the heat loading in these areas and verified that the additional heat load will not have an effect on the systems within these locations.

(10) BVPS-2 Safety Injection (SI) Accumulator Discharge Isolation Value Test - SI accumulator pressure is increasing as a result of the EPU conditions. The associated discharge motor operated values are administratively locked open during full power operations and, therefore, the need to test these values (functionally open at power) is no longer necessary. Additionally, this test was not performed at greater than 80 percent power during initial power ascension testing.

(11) BVPS-1 and 2 Automatic Steam Generator Water Level Control Test - BVPS-1 SGs are being replaced to support the uprated power conditions. PMT will be conducted to assure proper design and installation of the generators. For EPU conditions automatic operation of the SG level controller will be verified based on the revised steam flow and feedwater flow characteristics. This test will be performed at 100 percent EPU full power conditions.

(12) BVPS-2 Condensate Polishing System Test - the condensate polishing system is no longer used during full power operation. The system is currently used for water cleanup as the plant is coming out of a refueling outage. As a result of the EPU conditions, secondary plant process flow will increase to beyond the design maximum condensate flow and individual demineralizer limit for the system. As a result, no testing will be performed on the system at full power since the flow conditions at EPU will exceed the design capacity for the condensate polishing system and the system is no longer normally used at full power conditions.

(13) BVPS-2 Measurement of Steam Generator Moisture Carryover - for initial power-ascension testing, the test was used to verify that the moisture content of the steam entering the main header was not in excess of one quarter of a percent (0.25 percent). For the uprated conditions, the NSSS vendor has stated that the moisture carryover (MCO) will not exceed the current design limit of 0.25 percent and, therefore, the current design specifications and limits are still valid.

The NRC staff also reviewed Tables 4 - 7 of Attachment D, in the EPU supplemental information letter L-04-026, dated February 23, 2005, which provided the rationale for exclusion of certain large transient tests associated with the initial power-ascension programs for BVPS-1 and 2. In addition, the licensee provided further explanation and documented the basis for not performing certain tests as part of its February 23, 2005, submittal. In that submittal, the licensee stated that as a result of the review of the applicable section of the SRP, the original startup programs for the two units, recommendations from the NSSS vendor, no transient tests need to be performed as part of the EPU test program.

Specifically, the applicant reviewed the following transient tests performed at or above 80 percent power during initial power-ascension testing as part of their evaluation for the EPU conditions.

- Load swings
- Large load reduction
- Net load trip (BVPS-1)
- Plant load rejection (BVPS-2)
- Plant trip from 100 percent power

As part of the justification for not re-performing these tests at EPU conditions, the licensee cited the use and verification of the LOFTRAN computer code to evaluate plant response to both Condition I and Condition II initiating events at EPU conditions. As part of the verification process for the LOFTRAN code, the licensee compared the code output to actual BVPS unit transient data including reactor trip from 100 percent power, 100 percent load runback, and various step load changes. For the purposes of EPU, the LOFTRAN analysis inputs and models were updated to incorporate the EPU-related changes to setpoints and parameters associated with the EPU plant conditions. Additionally, the applicant cited use of the LOFTRAN code at BVPS-1 and 2 for current and original power levels, as well as the extensive experience of the NSSS vendor, Westinghouse, with accident analyses, control system performance, and equipment sizing studies at similar Westinghouse 3-loop NPPs such as North Anna Power Station, Units 1 and 2, Virgil C. Summer, and Shearon Harris.

The NRC staff also reviewed the following technical justifications provided by the licensee for not performing transient testing.

Load Swings - This test verified NSSS transient response, including the automatic reactor control system, when +10 percent step load changes were made via the turbine generator controls at the maximum rate. The initial test results for each unit indicated that the plants did not trip and no safety features were actuated. Automatic control systems performed satisfactorily to bring the plant to stable conditions. The test was performed at 30, 75, and 100 percent power for BVPS-1 and at 30, 50, and 100 percent power for BVPS-2.

The NRC staff reviewed the licensee's justification for not re-performing the load swing testing and noted that at the EPU thermal power level of 2910 MWt (NSSS Power), the 30, 50, and 75 percent power levels remain within the range of power levels tested in the original startup test program. Only the 100 percent uprate power level is above the range of power levels originally tested and is not enveloped by the original test results. The staff noted that the NSSS control systems functional design and hardware are not impacted as a result of the uprated conditions, and the licensee's analysis for the +10 percent step load change Condition I operating transients show acceptable stability, setpoints, and margin to reactor trip and ESF actuation.

Large Load Reduction - This test verified NSSS transient response, including automatic reactor control system, when a 50-percent step load reduction (rejection) was made via the turbine generator controls at the maximum rate. The initial test results for each unit indicated that for tests performed at 75-percent power level, all acceptance criteria were met. Two attempts were made during initial startup testing to perform a 100-percent load reduction on BVPS-1 but were unsuccessful. During the first test, an MSSV lifted due to a wiring error in the steam dump circuitry. The wiring error was corrected, and the transient test was repeated. The steam dumps operated satisfactory during the second test. During the second test, the reactor tripped and the main turbine tripped due to the main feedwater pumps tripping on low suction pressure. The station evaluated and accepted the test results since the protective features properly functioned. Additionally, as part of the current plant design, on a large load rejection, the feedwater heater bypass valve opens to lower system resistance, and provide additional head for the main feedwater pumps.

The NRC staff reviewed the licensee's justification for not re-performing the large load reduction transient testing. The licensee stated that such testing was not realistic for either unit and cited the following rationale. With respect to the design of the turbine system, turbine runbacks are generated in the RPS when ΔTs exceed their setpoints. The runback signals do not decrease turbine load by a specific amount but cycle until ΔTs reduce below their setpoint values. Additionally, neither unit has control circuitry that will automatically reduce load to or by 50 percent, and neither unit load follows. The turbine governor is normally controlled in manual by a valve position limiter. With respect to the generation of a 50-percent load reduction, the licensee noted that such an event could only occur by the opening of the switchyard breaker associated with the main output transformers at 50 percent power. The current design of the plants will generate a turbine trip and subsequent reactor trip at a power level above P-9 (49 percent full power). The staff noted that the NSSS control systems functional design and hardware are not impacted as a result of the uprated conditions and the applicant's analysis for the 50-percent load rejection Condition I operating transient shows acceptable stability, setpoints, and margin to reactor trip and ESF actuation at full-power EPU conditions.

Net Load Trip/Plant Load Rejection - This test verified plant response to a step loss of electrical load. Both units were originally designed to sustain a net load rejection without a reactor trip. This transient was initiated from power by opening the main transformer 345KV circuit breakers in the switchyard. The licensee provided justification for not re-performing the testing based on changes to the CLB. Specifically, as part of the BVPS-1 and 2 MUR uprating to 2697 MWt (NSSS Power), the licensing basis for the Condition I large load rejection operating transient was changed from a 100-percent net load rejection to a 50-percent load rejection. Therefore, the 100-percent net load rejection is not considered applicable to BVPS-1 and 2 and as a result, the Net Load Trip/Plant Load Rejection test is no longer required. The 50-percent load rejection is addressed under the large load reduction test above.

Plant Trip from 100 Percent Power - This test verified plant response to a plant trip from 100 percent power. Plant automatic controls are designed to bring the plant to stable conditions after the transient. For BVPS-1, an initial test was performed and results indicated that all acceptance criteria were met with the exception of the RTD response times. The NSSS vendor performed additional analysis, and the RTD response times were determined to be acceptable. For BVPS-2, an actual operational transient (an inadvertent turbine trip from 100 percent power) was used to satisfy this test. Following the trip, available data was forwarded to the NSSS vendor for evaluation. The NSSS vendor determined that the plant response to this turbine trip from 100 percent power was acceptable.

The licensee noted that as a result of original testing, data obtained from the plant response was used to verify the computer code model predictions, which were used for modeling plant transients. The dynamic response of the main steam piping, monitored during the turbine trip, was also demonstrated to be acceptable. The NRC staff noted that the licensee also performed evaluations for the RTS and the ESFAS at EPU conditions. The RTS and ESFAS functional design and hardware, including the installation of previously removed lead/lag filters in the BVPS-1 OTΔT and OPΔT instrumentation to restore original design capability, are shown to be acceptable for EPU conditions. The RTS and ESFAS setpoints, including the revised OTΔT and OPΔT setpoints and time constants to enhance analysis and operating margins and the BVPS-1 SG low-low and high-high level setpoints to accommodate SG replacement, are also shown to be acceptable for EPU conditions (EPULR, Section 5.10). Safety analyses were also performed for Condition II operating transients to show that the RTS and ESFAS systems and setpoints, including revised OPΔT and OTΔT setpoints, are acceptable for EPU conditions. The safety analyses showed that Condition II operating transients satisfied acceptance criteria and pressure control components were adequately sized.

The NRC staff also noted that in describing and justifying test exceptions or deviations the licensee adequately considered previous operating experience, the possible introduction of new thermal-hydraulic phenomena or system interactions, and margin reduction in safety analysis results for AOOs. Factors used to determine EPU test elimination included use of baseline operational data, updated computer modeling analyses, and industry experience.

Conclusion

The NRC staff concludes that, in justifying test eliminations or deviations, the licensee adequately addressed factors which included previous operating experience, introduction of new thermal-hydraulic phenomena or system interactions, and licensee staff familiarization with facility operation and use of operating and emergency operating procedures. The staff

determined that the licensee did not rely on analytical analysis as the sole basis for elimination of a power-ascension test from the proposed EPU test program. Construction, installation and/or pre-operational testing for each modification will be performed in accordance with the plant design process procedures, and on-going plant system operation is monitored and maintained under the current Maintenance Rule, calibration, and surveillance programs. The final acceptance tests will demonstrate that the modifications will perform their design function and integrate appropriately with the existing plant.

4. SRP Section 14.2.1, Section III.D - Adequacy of Proposed Testing Plans

Evaluation Criteria

SRP Section 14.2.1, Section III.D., specifies the guidance and acceptance criteria the licensee should use to include plans for the initial approach to the increased EPU power level and testing that should be used to verify that the reactor plant operates within the values of EPU design parameters. The test plan should assure that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the design basis for the facility. The predicted testing responses and acceptance criteria should not be developed from values or plant conditions used for conservative evaluations of postulated accidents. During testing, safety-related SSCs relied upon during operation should be verified to be operable in accordance with existing TS and Quality Assurance Program requirements. The following should be identified in the EPU test program:

- the method in which initial approach to the uprated EPU power level is performed in an incremental manner including steady-state power hold points to evaluate plant performance above the original full-power level;

- appropriate testing and acceptance criteria to ensure that the plant responds within design predictions including development of predicted responses using real or expected values of items such as BOL core reactivity coefficients, flow rates, pressures, temperatures, response times of equipment, and the actual status of the plant;

- contingency plans if the predicted plant response is not obtained; and

- a test schedule and sequence to minimize the time untested SSCs important to safety are relied upon during operation above the original licensed full-power level.

NRC Staff's Evaluation

The NRC staff reviewed Section 13, "Testing," of the EPULR which described power-ascension tests as they related to the proposed EPU implementation. In addition, the staff reviewed the licensee's supplemental submittals dated February 23, 2005 and March 10, 2006, which provided additional details regarding the development of the power-ascension testing for the EPU conditions. The staff found that the licensee had adequately considered EPU operating experience for similar designed plants (North Anna, Shearon Harris, and V.C. Summer) in determining the current proposed test plan for BVPS-1 and 2. The staff also found:

- Determination of the proposed tests and test plan addressed the effects of any new thermal-hydraulic phenomena or system interaction that may be introduced by the EPU through computer model analyses and/or operating plant experience. Previous operating experience, the initial startup test program report, and computer model analyses were the major influences on the proposed tests and test plan.

- The plant staff, through classroom and/or simulator training, will be familiarized with the operation of the plant under EPU conditions. The training will include plant modification and parameter value changes, implementation/execution of normal, abnormal, and emergency operating procedures, and accident mitigation strategies.

Additionally, during the tests, additional data will be taken initially at 3 percent above the current RTP of 2689 MWt and subsequently at 2.5-percent increments from 2770 MWt to the EPU RTP of 2900 MWt. Steady-state data will be taken at 95 percent and 100 percent of the current RTP so that operating performance parameters can be projected for the uprated power. The data will then be evaluated against design predictions and any identified discrepancies will be resolved prior to continuing with power ascension. BVPS senior plant management and experienced test personnel will evaluate all significant test deficiencies and anomalies at the initial 3-percent power plateau and each subsequent 2.5-percent power plateau before recommending power ascension to successive plateaus. Although no final test schedule has been developed, the NRC staff noted that BVPS-1 and 2 will follow typical startup procedures and TS requirements when the EPU is implemented.

<u>Conclusion</u>

The NRC staff concludes that the proposed test plan will be performed by qualified personnel and will adequately assure that the test objectives, test methods, and test acceptance criteria are consistent with the design basis for the facility. Additionally, the staff concluded that the test schedule would be performed in an incremental manner, with appropriate hold points for evaluation, and that contingency plans existed for cases where predicted plant response is not obtained.

5. Balance-of-plant (BOP) systems considerations

In light of the considerations that are discussed in SRP Section 14.2.1 for power uprates, the NRC staff requested additional information regarding the BVPS-1 and 2 EPU power-ascension testing for BOP systems. In response to the staff's request, the licensee provided supplemental information in a letter dated February 23, 2005. The staff reviewed the information that was provided and found that the licensee has adequately addressed the considerations discussed in SRP Section 14.2.1 with respect to the BOP area of review.

The NRC staff's review of the licensee's power-ascension and testing plan for BOP systems focuses primarily on two areas. One area deals with the capability of the atmospheric steam dump valves and the turbine bypass valves to discharge the steam flow mass flow rates that are credited for assuring adequate decay heat removal capability consistent with accident analysis assumptions and for preventing challenges to reactor safety systems in accordance with design-basis considerations. Because the licensee is not proposing to credit additional

steam dump or bypass valve capacity beyond what was originally established by the valve design specifications, transient testing for the purpose of demonstrating the capacities of the steam dump and turbine bypass valves is not necessary.

The other area of the NRC staff's review focuses on large transient testing that may be needed as a consequence of BOP modifications that are necessary for implementing the proposed power uprate. During the staff's evaluation of the BOP areas of review, no plant modifications of this nature that would warrant regulatory oversight and large transient testing were identified.

Based on a review of the information that was provided, the NRC staff has determined that with the limited scope of BOP modifications, no introduction of new thermal-hydraulic phenomena, and past plant experience combined with a demonstration of acceptable BOP performance during the planned power ascension test program, reasonable assurance exists that BOP systems will function as required for EPU operation.

Conclusion

The licensee has evaluated the impact of the proposed EPU on BOP systems and components, demonstrating that BVPS-1 and 2 are capable of providing safe and reliable operation at an uprated RTP of 2900 MWt. Based on the considerations that are discussed in this evaluation and in particular, recognizing that acceptable BOP performance will be demonstrated prior to commencing operation at the full EPU power level in accordance with the provisions of the licensee's power-ascension test program, the NRC staff finds that the licensee has adequately accounted for the effects of the proposed power uprate on the BOP systems and has adequately addressed the need for transient testing of BOP components and for large transient testing of BOP systems. Therefore, the NRC staff finds the proposed EPU to be acceptable with respect to BOP considerations.

C. Summary Conclusion

The NRC staff has reviewed the EPU test program in accordance with SRP Section 14.2.1. This review included evaluation of (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance necessary to demonstrate that plant equipment will perform satisfactorily at the proposed maximum licensed thermal power level, (2) deletions and exceptions to transient testing, and (3) the test program's conformance with applicable regulatory guidance and acceptance criteria. For the reasons set forth above, the staff concludes that the proposed EPU test program provides reasonable assurance that the plant will operate in accordance with design criteria and that SSCs affected by the EPU or modified to support the proposed power uprate will perform satisfactorily while in service. On this basis, the staff finds that the EPU testing program satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." Therefore, the staff finds the proposed EPU test program acceptable.

2.13 Risk Evaluation

2.13.1 Risk Evaluation of Extended Power Uprate

Regulatory Evaluation

A risk evaluation is conducted to (1) demonstrate that the risks associated with the proposed extended power uprate (EPU) are acceptable and (2) determine if “special circumstances” are created by the proposed EPU. As described in Appendix D of SRP Chapter 19 [67], special circumstances are any issues that would potentially rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements. The staff’s review covers the impact of the proposed EPU on core damage frequency (CDF) and large early release frequency (LERF) for the plant due to changes in the risks associated with internal events, external events, and shutdown operations. In addition, the staff’s review covers the quality of the risk analyses used by the licensee to support the application for the proposed EPU. This includes a review of licensee actions to address issues or weaknesses that may have been raised in previous staff reviews of the licensee’s individual plant examinations (IPEs) and individual plant examinations of external events (IPEEEs), or by an industry peer review. The NRC’s risk acceptability guidelines are contained in RG 1.174 [69]. Specific review guidance is contained in Matrix 13 of Review Standard RS-001 and its attachments. Further guidance on how to make a determination of adequate protection is provided in Appendix D to SRP Chapter 19.

Technical Evaluation

The NRC staff reviewed the EPU submittal [8] and the risk evaluation submitted by the licensee [62], as supplemented by responses to the staff’s RAIs [11, 18, 56, 59, 63, and 64]. The licensee’s risk evaluation compared the risks of the pre-EPU to the post-EPU plant design and operation. A combination of quantitative and qualitative methods was used to assess the risk impacts of the proposed EPU. The following sections provide the staff’s technical evaluation of the risk information provided by the licensee.

Probabilistic Risk Assessment Model Quality

The licensee used its at power, internal events, fire and seismic probabilistic risk assessment (PRA) models to assess the risk associated with implementing EPU for BVPS-1 and 2. The PRA model used is an update of the model developed to support the licensee’s response to GL 88-20.

The NRC staff recently approved a risk-informed TS amendment that used the same base PRA model as used by the licensee in the EPU risk assessment. The following information on the BVPS-1 and 2 PRA models is excerpted from the SE for that amendment [65]:

> The PRA models . . . are updates of the original BVPS-1 and 2 IPE models developed in response to GL 88-20. The scope of these PRA models encompasses both level 1 and level 2, internal and external [e.g., fire and seismic] initiating events during power operation . . . The maintenance and updating of the BVPS-1 and 2 PRA models are controlled by . . . [an] administrative procedure [that] ensures that the PRA models are kept current with the plant design and operation.

In addition, the NRC staff conducted an on-site audit of the licensee’s PRA and EPU risk assessment. One focus of this audit was PRA quality, particularly with respect to maintaining configuration control of the model. The audit team reviewed the licensee's process and procedure for PRA model configuration control and compared them to the ASME PRA

standard, Section 5 [68]. The audit team also reviewed selected facts and observations from the industry peer review of the licensee PRA models and reviewed selected PRA model documentation.

The key audit finding was that the licensee's risk assessment of the impact of EPU implementation did not employ consistent assumptions in both the pre-EPU base case and the post-EPU analysis for non-EPU changes. The risk assessment also included non-EPU related changes and model enhancements. At the NRC staff's request, the licensee provided an updated risk assessment of EPU-related changes only, that included consistent assumptions which are presented in the "At-Power Risk Evaluation Results" Section later in this SE.

The pre-EPU risk numbers from the licensee's PRA are presented in Table 1 below.

Table 1: Estimated At-Power Risk, Pre-EPU Implementation (per reactor year)		
	BVPS-1	BVPS-2
Internal Events CDF	7.45E-6	2.01E-5
Fire CDF	4.60E-6	5.29E-6
Seismic CDF	1.17E-5	9.54E-6
Total CDF	2.37E-5	3.49E-5
Total LERF	1.03E-6	1.12E-6

Based upon the above, the NRC staff finds that the PRA used in support of the EPU is of sufficient quality, scope, and level of detail to analyze the risks stemming from the EPU, consistent with the guidance in RG 1.174 (Section 2.2.3), SRP Chapter 19 (Sections III.2.2.2, III.2.2.3, III.2.2.4, and Appendix A) and SRP Chapter 19.1, and is, therefore, acceptable. The risk impacts of EPU implementation are presented later in this SE in Table 2, in the section titled "At-Power Risk Evaluation Results."

Level 1 Internal Events Risk Evaluation

Initiating Event Frequencies

The BVPS-1 and 2 Level 1, internal events PRA models include the following initiating events: LOCA, SGTR, LOOP, transient, loss of support systems, and ATWS. The PRA models also include the potential for a consequential LOOP (i.e., a LOOP that occurs as a consequence of some other initiating event). The licensee reviewed these initiating events to determine the potential effects of the EPU on the initiating event frequencies.

LOCA - The BVPS-1 and 2 PRAs includes five LOCA events, ranging from excessive LOCA to

small LOCA (isolable and non-isolable). The licensee stated that the frequency of LOCA events are not affected by the EPU. The NRC staff concurs that EPU is not expected to increase LOCA initiating event frequencies.

SGTR - The licensee evaluated the SGs, (RSGs at BVPS-1; OSGs at BVPS-2) at the EPU conditions, and concluded that the generic SGTR initiating event frequency will not be impacted by EPU. Specifically, for both BVPS-1 and 2, the SGs were analyzed at the EPU conditions in the areas of thermal-hydraulic performance, structural integrity, U-bend fatigue, tube wear, tube repair limit, and tube degradation.

The licensee replaced the BVPS-1 SGs prior to EPU implementation. The RSGs were designed and analyzed for operation at EPU conditions. The RSGs employ a number of design enhancements relative to the OSGs, including different tubing material, a different tube support plate design and a different tube-to-tubesheet joint. The licensee expects SGTR frequency to decrease for BVPS-1 because the Alloy 690 tubes in the RSGs are less susceptible to tube ruptures than the tubes in the OSGs. The licensee estimated that the BVPS-1 SGTR frequency will decrease by a factor of about two, resulting in a net reduction in CDF and LERF for that unit, even after EPU implementation. The NRC staff reviewed the proprietary response to an RAI [11] that provided the methodology and other data used to estimate the SGTR frequency for the RSGs. The method included operating data and the results of expert elicitation. The staff determined that the operating data supports the conclusion that the Alloy 690 SG tubes are less likely to experience a tube rupture than the Alloy 600 tubes. The staff asked the licensee to estimate the change in risk from EPU separate from any consideration in the reduction of SGTR frequency, which is presented in the "At-Power Risk Evaluation Results" Section below (Table 2).

BVPS-2 will continue to use the OSGs for EPU. The licensee's analysis of the BVPS-2 SGs showed that all projected thermal-hydraulic operating characteristics were acceptable. The analysis showed no concerns of thermal performance deficiency, excessive moisture carryover, hydrodynamic instability or local dryout on tube walls. The licensee concluded that the BVPS-2 SGs will have acceptable performance at EPU conditions.

To address uncertainty in the SGTR risk analysis, the NRC staff considered the sensitivity of SGTR risk to an assumed increase in the SGTR frequency. The BVPS-1 and 2 pre-EPU SGTR CDF and LERF are on the order of 1E-6 per year at each unit. A hypothetical 10-percent increase in SGTR frequency would increase SGTR CDF and LERF by about 1E-7 per year. An assumed 100-percent increase in the SGTR frequency would increase CDF and LERF by about 1E-6 per year. This latter value is at the RG 1.174 upper guideline value for an LERF increase to be considered "small." However, based on the licensee's analysis and the relatively small power uprate being requested (8 percent), the SGTR frequency is not expected to increase.

The NRC staff concurs with the licensee's conclusion that SGTR frequency is not expected to increase as a result of EPU implementation because the licensee has analyzed the BVPS-1 and 2 SGs for operation at the increased thermal power levels and the associated acceptance criteria are met, and notes that, if a small increase in SGTR frequency were to result from EPU implementation, a correspondingly small increase in CDF and LERF would not rebut the presumption of adequate protection of public health and safety.

LOOP - The frequency of LOOP events is dictated by the reliability of the switchyard and grid.

The LOOP initiating event frequency was derived by using plant-specific data and generic industry data through a Bayesian updating process. The licensee stated that studies were performed to evaluate the impact of Unit 1 and Unit 2 EPU operation on transmission system grid stability. The results of these studies yield comparable results to those obtained from the previous, pre-EPU study. In addition, the 345 kilo-volt (kV) and 138 kV switchyards were evaluated. This evaluation concluded that equipment and components in the 345 kV and 138 kV switchyards, including the overhead lines between the station and those switchyards, are adequate under EPU conditions. In addition, the licensee will implement modifications to ensure that the LOOP frequency is not adversely affected by EPU conditions (e.g., changes to the 4160 volt transformer tap positions and modification of the cooling system for the BVPS Unit 2 main electrical transformer). The plant response following a unit trip will be essentially the same following the EPU as is currently modeled. Therefore, EPU is not expected to increase LOOP frequency.

As part of another licensing action [66], the licensee provided the following information related to LOOP: the New York Area blackout of August 2003 did not adversely impact either of the BVPS units enough to result in a plant trip or LOOP. However, a sensitivity study was performed on the LOOP initiating event frequency assuming that each of the units observed one additional LOOP event through the end of 2003. The results of this LOOP sensitivity study was an increase in LOOP frequency of about 41 percent (BVPS-1) and 45 percent (BVPS-2), which resulted in an increase in CDF of less than 1E-7 per year in each case. Although not performed at EPU conditions, similar small increases would be expected for a similar sensitivity analysis at EPU conditions.

The NRC staff concludes that, based on the licensee's analysis, the LOOP frequency should not be adversely affected by EPU. The staff also notes that, based on the sensitivity analysis, the risk impact of EPU from LOOP events should be small, even if an increase in LOOP frequency is assumed.

Consequential LOOP - The licensee stated that the probability of a consequential LOOP is not expected to be impacted by the EPU. One part of consequential LOOP is that loss of a unit's electrical output because of a trip or other initiating event can result in a cascade effect if the transmission system is not adequately designed; increased unit electrical output due to EPU can exacerbate this effect. The licensee analyzed transmission system grid stability as discussed under "LOOP Frequency," above. Another potential source of consequential LOOP is the fast bus transfer that takes place following a trip of the unit. The NRC staff would not expect fast bus transfer failures to increase as a result of EPU, since the hardware is not being modified for EPU. The staff concludes that the probability of consequential LOOP is not impacted by EPU.

Transient Event - As part of the EPU effort, the licensee reviewed plant systems for continued operability at the EPU conditions. In some cases, system changes have been made so that the systems will adequately perform their functions at the EPU conditions (e.g., resetting control and protection system instrument setpoints to maintain operating margins). Based on this, the NRC staff concludes that the initiating event frequencies for transients would not be expected to change at EPU conditions.

Loss of Support Systems - The support system initiating event frequencies were quantified

using fault tree models. The initiating event frequencies quantified in this manner include those for loss of AC or DC power sources, loss of service water, loss of primary or secondary component cooling water, loss of station instrument air, and loss of containment instrument air. As discussed below under “Component Failure Rates,” equipment and system reliability is not expected to be adversely affected by EPU. The licensee evaluated the success criteria for the support systems and determined them to be unchanged by EPU. Since the success criteria and reliability of these systems are expected to remain the same, the NRC staff agrees that the initiating event frequencies from these support systems will not be impacted by EPU.

ATWS - Failure of the reactor to trip automatically following an initiating event (i.e., ATWS) is considered in the PRA models in the course of developing plant response scenarios. The licensee evaluated the NSSS control systems for stability and operability, and evaluated the CRDMs. The NRC staff agrees with the licensee’s conclusion that the frequency of an ATWS event would not be affected by the EPU conditions.

Overall EPU Impact on Initiating Events - The NRC staff concurs with the licensee’s assessment of the impact of the proposed EPU on the frequency of initiating events, and concludes that the initiating event frequencies should not be appreciably impacted by the proposed EPU, as long as the operating ranges or limits of equipment are not exceeded. The licensee has evaluated the impacts of EPU on equipment to ensure operating ranges and limits are maintained, implementing plant modifications where necessary. In addition, the staff notes that any changes in initiating event frequencies following implementation of the proposed EPU would be identified and tracked under the licensee’s existing performance monitoring programs and processes (e.g., Maintenance Rule program).

Component Failure Rates

The licensee performed an evaluation to identify the effects of the EPU on the functionality of plant systems, including decay heat removal, containment, steam conversion, RCS, engineered safety features, reactivity control, and electrical/instrumentation and controls. A review of the engineering change packages associated with the EPU was performed to determine their effect on systems and associated equipment that are important to plant risk.

The licensee concluded that plant changes associated with the EPU will have no adverse effect on system functions important to plant risk. Plant modifications were made to maintain or improve the performance of certain equipment under EPU conditions so that plant systems and equipment will continue to be operated within design constraints and component failure rates, and equipment unavailability will not significantly change with the implementation of the EPU. Thus, system functionality is not impacted. In addition, existing component monitoring programs, such as preventive maintenance and Maintenance Rule programs, would identify any additional degradation as a result of the EPU. While the EPU could result in some components being refurbished or replaced more frequently, which may result in increased unavailability if performed while the plant is on line, the functionality and reliability of the components will be maintained to the current standard.

The NRC staff finds that it is reasonable to conclude that equipment reliability will not change, as long as the operating ranges or limits of the equipment are not exceeded. For equipment that is operated within its operating ranges or limits, the staff notes that the licensee’s component monitoring programs, as identified above, should detect any significant degradation

in performance and the staff expects these programs to maintain the current reliability of the equipment. As for potential increased unavailability, the staff notes that the Maintenance Rule requires the licensee to balance reliability and availability and to take appropriate corrective actions when the performance or condition of an SSC does not meet established goals.

Accident Sequence Delineation and Success Criteria

The licensee evaluated the impact of the proposed EPU on PRA accident sequence delineation and success criteria. The licensee considered the sequences modeled in the PRA; e.g., transients, LOCAs and ATWS events. At the NRC staff's request, the licensee also verified that the PRA AFW success criteria remained valid post-EPU and that the risk associated with crediting containment accident pressure to provide NPSH was negligible. These evaluations are discussed in this section.

Impact of EPU on Auxiliary Feedwater Success Criteria - The design basis loss of normal feedwater accident (Section 5.3.7.2 of Reference 1) resulted in a change to the AFW success criteria for EPU, compared to pre-EPU power levels. In particular, the BVPS-1 success criteria increased from "any single AFW pump supplying any SG" to "both motor-driven AFW pumps or the turbine-driven AFW pump supplying two SGs." BVPS-2 exhibited the same change with respect to the number of AFW pumps; two SGs were already assumed to be necessary due to BVPS-2 having a smaller atmospheric dump valve capacity than BVPS-1.

The NRC staff questioned whether the AFW success criteria for the PRA were similarly impacted by EPU. The licensee performed an analysis to determine whether EPU would result in a similar change to the PRA success criteria [18]. Realistic assessments for a loss of normal feedwater event were performed for BVPS-1 and 2 using the Westinghouse, "LOFTRAN," code. The results showed that the minimum AFW flow required was less than the capacity of one motor-driven pump, assuming realistic conditions with either the condenser steam dump valves or the atmospheric steam dump valves available. Additionally, a best-estimate analysis was performed using the modular accident analysis program (MAAP) code [56] for both units. The results of these MAAP analyses show that the pre-EPU and post-EPU PRA success criteria (i.e., one AFW pump feeding one SG - BVPS-1; one AFW pump feeding two SGs - BVPS-2) remain valid for the LONF transients.

Station Blackout (SBO) - The licensee analyzed SBO sequences at EPU power levels using the MAAP code. The timing to core damage was impacted slightly in some cases. A shorter time to core damage for a given scenario translates into a less optimistic probability of recovering offsite power, since offsite power would have to be restored earlier. The licensee confirmed that the impact of the timing changes on CDF and LERF was not significant. The electric power recovery model is discussed further in the next section, "Operator Actions and LOOP Recovery."

For BVPS-1, the licensee noted an increased time to core damage for some SBO scenarios at EPU conditions compared to pre-EPU conditions. This counter-intuitive result was due to a change in SI accumulator inventory. At the NRC staff's request, the licensee performed a sensitivity analysis using consistent accumulator parameters for the pre- and post-EPU MAAP analyses, which verified that, considering only increased reactor RTP, the time to core damage decreases slightly, as expected.

SBLOCA - SBLOCA sequences are defined in the BVPS-1 and 2 PRAs as those smaller than 2 inches equivalent diameter, but larger than breaks for which the normal charging system could provide continuous makeup. The EPU is not expected to have any impact on injection capability, but EPU could impact the SBLOCA success criteria related to operator actions to cool down and depressurize, or to implement feed-and-bleed. The licensee verified that SG cooldown and depressurization success criteria will not change as a result of EPU or due to the addition of cavitating venturis in the AFW lines. The licensee verified that the feed-and-bleed success criteria, as currently modeled in the PRA, remain the same at EPU conditions (i.e., one pressurizer PORV). For SBLOCA sequences involving failed high-head SI, operators will still be able to depressurize the RCS with sufficient time available to use low-head SI to prevent core damage after EPU implementation. As discussed in the next section, "Operator Actions and LOOP Recovery," the licensee validated the ability of the operators to perform these actions under EPU conditions using simulator observations or walk-through/talk-through techniques.

Medium-break and LBLOCA - The medium-break LOCA break spectrum includes breaks ranging from 2 inches up to 6 inches equivalent diameter. The smaller end of the break spectrum could be similar to the SBLOCA scenarios; the SBLOCA conclusions regarding cooldown/depressurization and feed-and-bleed success criteria would apply. The success criteria for the larger end of the medium-break spectrum, and the large-break spectrum, are not expected to be affected by EPU, because the design-basis criteria (i.e., one-of-two low-head SI pumps delivering flow through two-of-two intact cold leg injection paths and injection from two-of-two intact cold leg accumulators) remain unchanged.

General Transients - The transient-related success criteria also did not change as a result of EPU. The secondary side decay heat removal success criteria did not change. The licensee analyzed a loss of all normal and AFW as a representative severe transient sequence and verified that the feed-and-bleed success criteria were not altered.

Loss of Service Water/Loss of River Water - The primary core damage mechanism resulting from a loss of service water or loss of river water is a consequential RCP seal LOCA. Thus, this category of sequences would have similar sensitivities to the EPU as discussed above for SBO.

Anticipated Transient Without SCRAM - The licensee noted one change associated with the EPU that affects ATWS-related success criteria. The addition of cavitating venturis to the AFW system at BVPS-1 precludes the ability to deliver full flow from all 3 AFW pumps to the SGs. However, the existing PRAs already take no credit for full AFW delivery in response to ATWS, thereby resulting in a somewhat conservative prediction of ATWS risk, which is, therefore, unaffected by the EPU. The NRC staff notes that such conservative assumptions mask the actual change in risk. However, based on the total risk (CDF and LERF) calculated by the licensee for both units (refer to Table 2 in the "At-Power Risk Evaluation Results" Section below), the staff does not find special circumstances that would rebut the presumption of adequate protection of the public health and safety. In addition, ATWS scenarios account for less than 1 percent of total CDF for both units [66], so the actual increase in risk from this source would not change this conclusion.

Impact of EPU on Containment Accident Pressure for NPSH -The pre-EPU licensing basis for BVPS-1 allows consideration of containment accident pressure in the calculation of the NPSH

available for the inside and outside recirculation spray pumps (BVPS-2 does not need to credit containment accident pressure in the NPSH calculations for the current power level or at EPU conditions because the BVPS-2 recirculation pumps are installed at a lower elevation relative to the BVPS-2 sump than at BVPS-1). The NRC staff questioned whether the EPU would exacerbate the need for crediting containment accident pressure on BVPS-1.

The licensee stated [56] that there is an insignificant change in risk resulting from EPU, with respect to crediting containment accident pressure in the NPSH calculations. The required containment accident pressure is of relatively short duration (10-20 minutes), and margin exists in the NPSH calculations, because all parameters are biased simultaneously in the conservative direction. The difference in duration of containment accident pressure required in the pre-EPU case, compared to the post-EPU case, is on the order of a minute, based on a representative calculation performed by the licensee. In addition, the licensee performed tests of the recirculation spray pumps that demonstrated that the pumps are capable of stable operation at conditions where NPSH is reduced below the standard requirement. To further demonstrate that there is an insignificant risk impact as a result of EPU effects on the credit for containment accident pressure, the licensee performed a sensitivity study to determine the impact of operation of the recirculation spray pumps under accident conditions, with failures of containment isolation for systems which communicate directly with the containment atmosphere. The largest such penetration at BVPS-1 is 2 inches in diameter. Even with a 3-inch hole in such a system, the licensee demonstrated that margin exists in the NPSH available to the recirculation spray pumps. In other words, containment accident pressure, even with a 3-inch hole to the containment atmosphere, would be sufficient to provide adequate NPSH to these pumps. Additionally, the licensee estimated the frequency of a containment isolation failure coincident with an LBLOCA to be approximately 1.0E-8 per year.

On the basis of the preceding information, the NRC staff agrees with the licensee's conclusion that the change in risk associated with EPU, with respect to crediting containment accident pressure for NPSH, is insignificant. The staff notes that, for EPU to result in a risk increase from this mechanism, there would have to be a containment isolation failure or other leakage source that would cause pump failure at EPU conditions but would not cause pump failure at pre-EPU conditions. Given the approximately 1-minute difference in duration of the need for crediting containment accident pressure, only a very limited range of leak rates would cause recirculation spray pump cavitation post-EPU that would not cause the same condition pre-EPU. In other words, a large leak would result in cavitation in both pre- and post-EPU scenarios; a slow leak would result in cavitation in neither. Coupled with the licensee's tests of the recirculation spray pumps, this supports the conclusion that the change in risk is insignificant.

Impact of Modifications on Accident Sequence Delineation and Success Criteria - The licensee described the process it used to determine what modifications would impact the PRA models [11]. Modifications were evaluated using a two-step screening process to determine whether there would be a significant impact on risk due to a plant modification. The first step considered whether the modified system or component is currently modeled in the PRA, or not modeled but considered potentially important to plant risk. The second step used the guidelines in the SRP, Chapter 19.0, and considered whether the change would impact the system performance in a potentially negative or non-conservative manner, whether the change would impact the system design in such a way as to alter system reliability models, and whether the change would impact the support function of the system in such a way as to alter the dependencies in the

model.

The NRC staff reviewed the licensee's screening process and discussed it with members of the licensee's staff during an onsite audit of the PRA model. The staff concluded that the licensee's process appeared reasonable to ensure that modifications important to risk were identified. The licensee's review of several modifications that were not screened out is summarized below.

The charging system modifications (i.e., rethrottling and rotating assembly replacement) were evaluated at EPU conditions using MAAP. It was concluded that these modifications have no impact on the PRA success criteria at EPU conditions. The BVPS-1 main feedwater (MFW) system fast-acting feedwater valves and AFW cavitating venturis were added to the BVPS-1 PRA model. The licensee concluded that these components are not significant contributors to risk, based on low Fussell-Vesely importance. The licensee stated that the BVPS-2 feedwater valve replacements were one-for-one replacements and will not impact any modeled component or success criteria.

Overall EPU Impact on Accident Sequence Delineation and Success Criteria - The NRC staff concurs with the licensee's assessment that the EPU will have no adverse impact on accident sequence delineation or success criteria.

Operator Actions and LOOP Recovery

Human Reliability Analysis (HRA) - EPU has the general effect of reducing the time available for the operators to complete recovery actions, because of the higher decay heat level after EPU implementation. Reduced time available can increase the probability of operator failure. The BVPS-1 and 2 PRA models use the Success Likelihood Index Method (SLIM) for evaluating human error probabilities in the HRA. This method includes available time as a performance shaping factor, but is not conducive to translating small changes in time available into realistic changes in human error probability. Also, the base PRA models (i.e., pre-EPU) used simplified thermal-hydraulic "hand calculations" to establish approximate, and often conservative, operator action timing - although the BVPS-2 base PRA model did use MAAP analyses in a few cases. The post-EPU PRA models used more realistic MAAP analyses to establish the timing for most operator actions. In many cases, the MAAP available times were longer post-EPU than the pre-EPU timings, due to the pre-EPU simplified calculations.

Because of different thermal-hydraulic methods and limitations of the SLIM method (with respect to operator action timing), the licensee initially did not provide a meaningful comparison of the risk impact of the EPU. Also, there were other changes made to the PRA model that were not EPU-related, including model enhancements that lower the risk values. For example, an improved RCP seal LOCA model was implemented, a reduced SGTR frequency was applied in the BVPS-1 PRA, due to the RSGs, and miscellaneous conservative modeling features were made more realistic. These actions resulted in masking the risk impact of EPU to the extent that the licensee reported a risk decrease compared to the pre-EPU PRA CDF and LERF. Therefore, the NRC staff requested that the licensee perform a sensitivity analysis to demonstrate the potential impact of EPU due to all sources, but without being masked by model enhancements or changes unrelated to EPU.

To answer this request, the licensee evaluated operator actions as either impacted or not

impacted by EPU, and, for those impacted, adjusted the performance shaping factor for time available in the SLIM analysis. The NRC staff notes that this approach will yield higher human error probabilities when the time available is less, but also notes that SLIM does not provide a quantitative way to factor small changes in available time into the resulting probabilities. However, this sensitivity study, coupled with the validation described in the next paragraph, provides confidence that a significant increase in risk due to EPU impact on human error probabilities will not occur. The licensee also evaluated PRA modeling changes to ensure that a valid comparison of pre- and post-EPU risk was made. This sensitivity analysis, performed by the licensee in response to the staff's request, estimated the impact of EPU on the HRA, but also ensured that the pre- and post-EPU PRA models were consistent with respect to model enhancements, corrections, and non-EPU changes. The sensitivity analysis resulted in an increase in internal events CDF due to EPU of 3.0E-7 per year on BVPS-1 and 2.9E-7 per year on BVPS-2. These increases are considered "small" according to RG 1.174 (impact on LERF is presented later in the discussion of Level 2 risk).

The NRC staff also requested that the licensee provide the actual post-EPU timing for operator actions that were important to risk and that have relatively short times available for the operators to perform them. The staff further requested that this information include an assessment as to whether any of these operator actions were precluded as a result of the decreased time available and the basis for that judgment. The licensee reviewed those operator actions to determine if the total time available, per thermal-hydraulic analysis, was sufficient to complete the operator action. The review considered the total time available, which includes the time from the beginning of the sequence until the operator is cued to perform the action, and the time to perform the action. The results showed that the operator actions can be performed in the time available based on EPU conditions. The licensee confirmed the ability to accomplish these operator actions in the available time by simulator observation or by a talk-through/walk-through of the action (or both in several cases).

Electric Power Recovery - The electric power recovery model in the PRA considers the non-recovery of electric power in sequences for which offsite and emergency AC power are lost. The licensee used a time-integrated model for failures and recovery actions, using the time to core damage results of the MAAP thermal-hydraulic analyses as input, to calculate an electric power non-recovery factor for each SBO sequence. The licensee stated that the time to core damage for most of the SBO sequences decreases with the EPU conditions (refer to the SBO discussion in the preceding section). In the time-integrated model for offsite power recovery, shorter time available results in a higher probability of non-recovery for the SBO scenarios. The licensee determined [11 and 64] that there is an insignificant impact on CDF and LERF from this change.

Overall EPU Impact on Operator Actions and LOOP Recovery - The licensee concluded that the EPU will result in shorter time available to perform some operator actions, including the time available to restore offsite power. Shorter times can result in higher human error probabilities for time-critical operator actions. These impacts were evaluated in a sensitivity analysis that estimated the impact of EPU on the HRA and used EPU timing for the offsite power non-recovery probability estimates. The licensee also verified that, using realistic operator action timing, no important, time critical operator actions were precluded by the shorter times post-EPU.

The NRC staff concludes that the licensee's sensitivity analysis provides a reasonable way to

consider how large the EPU risk impact could be by increasing the importance of time in the SLIM calculation for affected operator actions. This, coupled with verification that EPU will not result in the inability to perform any operator actions, provides reasonable assurance that adequate protection of public health and safety will be maintained.

Level 1 Internal Fire Risk Evaluation

An analysis of the plant changes resulting from the EPU, indicates that these changes are not expected to result in new internal fire initiators, nor are they expected to result in new internal fire core damage or LERF scenarios. The fire initiating event frequency is dictated by combustible loading within the area and is, therefore, not affected by the EPU. Plant changes associated with the EPU do not create any additional external fire hazards, nor do the changes increase the intensity of existing hazards.

The BVPS-1 and 2 plant changes do have a small impact on the performance of necessary mitigation systems in the event a fire occurs. Changes to the HRA, as well as plant modifications to the AFW and MFW systems (e.g., the additional AFW cavitating venturis adds an additional system failure mode), resulting in a small increase in risk. The licensee estimated that the BVPS-1 fire CDF would increase by 3.9E-8 per year and the BVPS-2 fire risk would increase by 6.4E-8 per year. These increases are considered small, per the RG 1.174 acceptance criteria.

The NRC staff finds that the licensee's evaluation of the impact of the proposed EPU on internal fire risk is reasonable. The staff concludes that there are no issues concerning internal fires that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

Level 1 Seismic Risk Evaluation

A review of the BVPS-1 and 2 seismic PRAs determined that the dynamic response of the RCS, considering system operating parameters, is consistent with the EPU that the original analysis remains applicable to the EPU conditions. An analysis of the BVPS-1 and 2 plant changes resulting from the EPU indicates that these changes are not expected to result in changes in SSCs' response to a seismic initiator, nor do they result in new seismic core damage or LERF scenarios. The plant changes have a negligible impact on the structural response of the plant, and they have a small impact on the availability and performance of necessary mitigation systems for a seismic event. Equipment installed or modified as a result of EPU will meet seismic design criteria.

The licensee estimates the change in seismic CDF at both units to be less than 1.0E-09 per year. This small change is due to additional failure modes being added to the models for systems modified for EPU, such as for the AFW cavitating venturis.

The NRC staff finds that the licensee's evaluation of the impact of the proposed EPU on seismic risk is reasonable. The staff concludes that there are no issues concerning earthquakes that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

Level 1 Other External Events Risk Evaluation

For the PRA external events evaluation of high winds, floods, and other external events, the licensee used the progressive screening approach described in NUREG-1407, "Procedure and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities." The plant modifications related to the EPU do not affect the high winds, floods, and other external events analysis. Thus, the IPEEE external events evaluation is applicable to the EPU conditions.

The NRC staff finds that the licensee's evaluation of the impact of the proposed EPU on other external event risk is reasonable because it is based on a methodology previously accepted by the staff for use in IPEEEs and EPU risk evaluations. The staff concludes that there are no issues concerning other external events that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

Level 2 Evaluation

An evaluation was performed to identify the effects of the EPU on BVPS-1 and 2 LERFs. The dominant contributors to LERF are SGTR events and interfacing system LOCAs outside containment. The licensee determined that plant changes associated with the EPU will have an insignificant or no adverse impact on these contributors.

As stated above, the RSGs are expected to be more resistant to tube failures, so the frequency of SGTR is expected to decrease. Consequently, the BVPS-1 LERF is expected to decrease as a result of the lower SGTR initiating event frequency.

Other LERF contributions that were explicitly considered by the licensee, included direct containment heating, hydrogen burns, steam explosions, induced SGTR, and containment isolation failures. Current (pre-EPU) sub-atmospheric containment modeling in the PRAs assumes no pre-existing containment isolation failures. This assumption remains valid for post-EPU because, even with containment conversion, slightly sub-atmospheric conditions will be maintained. The containment vacuum pumps would not be expected to be able to maintain that condition in the event of a pre-existing leak sufficient to impact LERF. The licensee reported the total LERF increase (including internal events, fires and seismic), based on the sensitivity analysis, to be 5.8E-8 per year for BVPS-1 and 4.6E-8 per year for BVPS-2.

The NRC staff finds that the licensee's evaluation of the impact of the proposed EPU on LERF is reasonable. The staff concludes that there are no issues concerning LERF that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

At-Power Risk Evaluation Results

The increase in total CDF and LERF attributable to the EPU, based on similar modeling methods pre- and post-EPU and the HRA sensitivity results, are presented in the following table.

Table 2: Estimated Risk from EPU Implementation (per reactor year)

	BVPS-1	BVPS-2
Increase in Total* CDF	3.4E-7	3.6E-7
Increase in Total LERF	5.8E-8	4.6E-8
Total CDF, post-EPU	2.3E-5	3.3E-5
Total LERF, post-EPU	5.0E-7	1.1E-6
* Total includes internal events, seismic and fire CDF/LERF		

The total post-EPU risk estimates are actually improvements over the pre-EPU PRA model of record results. One reason that the estimated CDF and LERF decrease is the improved HRA human error probabilities resulting from realistic MAAP timing that replace the conservative hand calculations. These are not real risk reductions, but rather removal of conservatism from the pre-EPU analysis. However, BVPS-1 LERF also decreases due to replacement of SGs that are expected to be less susceptible to SGTR events. The corresponding decrease in SGTR frequency results in a noticeable, beneficial impact on the BVPS-1 LERF.

The increases in total CDF and LERF were within the RG 1.174 guidelines for being “small.” The total CDF and LERF values are not relatively high and do not raise concerns of adequate protection.

The NRC staff finds that the licensee’s evaluation of the impact of the proposed EPU on risk is reasonable and concludes that the base risk due to the proposed EPU is acceptable and that there are no issues that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

Shutdown Risk Evaluation

BVPS-1 and 2 do not have quantitative PRA shutdown risk assessment models. The impact of the EPU on plant risk at low power and shutdown risk was evaluated in a qualitative manner by addressing the questions posed in Table III-1 of SRP 19.0, “Use of Probabilistic Risk Assessment in Plant-Specific, Risk-Informed Decision-Making: General Guidance,” to determine if the impacts on shutdown risk would be important. Based upon the responses to the SRP Chapter 19.0 questions on shutdown risk, the increase in decay heat is expected to result in a small decrease in the time available for operator actions during shutdown operations.

The BVPS-1 and 2 Shutdown Safety Administrative Procedure provides guidance for evaluation of shutdown safety and for surveillance during plant operating Modes 3, 4, 5, and 6 for planned and forced outages. It requires monitoring of the plant defense-in-depth features available during these operating modes, provides guidance for evaluating the adequacy of protective measures, and specifies actions to be taken to ensure that there are adequate protective measures in place. The administrative procedure requires development of a Pre-Outage Shutdown Safety Review of key shutdown safety functions. This guidance will continue to be used following the EPU. The evaluation of the questions posed by SRP Chapter 19.0 follows.

1. Will these changes affect the shutdown schedule?

The RHR system performance evaluation concluded that the RHR system remains adequate to maintain refueling temperatures and a uniform boron concentration in the RCS. Since the decay heat levels are expected to be slightly higher at EPU conditions, it may take a few hours longer to achieve cold shutdown. This will cause very little change in the shutdown schedule and has no direct safety impact on the schedule.

2. Will these changes affect operator ability to respond?

The possible initiating events during shutdown are generally defined as loss of the shutdown safety functions. The EPU does not increase the frequency of these initiators, but may impact the operators' ability to respond to the loss of shutdown safety functions. The following shutdown safety functions are typically tracked during an outage:

RCS Decay heat removal - The RHR system performance evaluation notes that the RHR system remains adequate to maintain refueling temperatures and a uniform boron concentration in the RCS. The increase in decay heat due to EPU will decrease the time for the operators to respond to a loss of shutdown cooling.

Maintaining an adequate defense-in-depth for this safety function at all times, via the BVPS-1 and 2 Shutdown Safety Administrative Procedure, minimizes the impact of this decreased response time. A Pre-Outage Shutdown Safety Review is prepared for each refueling outage according to the guidance of the administrative procedure. The current revision of this procedure includes guidance for evaluating the defense-in-depth of RCS decay heat removal.

RCS Inventory Control - The increase in RCS temperature and the increase in decay heat will decrease the time for the operators to respond to a loss of RCS inventory control. Maintaining an adequate defense-in-depth for this safety function at all times, via the Pre-Outage Shutdown Safety Review, minimizes the impact of this decreased response time. The Pre-Outage Shutdown Safety Review is prepared according to the guidance of the Shutdown Safety Administrative Procedure. The procedure includes guidance for evaluating the defense-in-depth of RCS inventory.

Alternating Current Power Availability - The increase in RCS temperature and the increase in decay heat will decrease the time for the operators to respond to a loss of electrical systems. Since the electrical systems support the systems required for the other safety functions, maintaining an adequate defense-in-depth for this safety function minimizes the impact of this decreased response time. In addition to the requirements for the other safety functions, the Shutdown Safety Administrative Procedure includes guidance for evaluating the defense-in-depth of AC power availability.

Reactivity control - The non-LOCA safety analysis section of the EPULR, specifically Section 5.3.5, describes the analysis of the uncontrolled boron dilution event for EPU conditions. The increase in rated power was found to have a negligible impact on the results of the boron dilution event. The analysis showed that for dilution during refueling, dilution during cold shutdown with the RCS filled, and dilution during cold shutdown with the RCS partially drained, the operator is alerted in time to take appropriate action to mitigate the event.

Containment Integrity - The containment integrity safety function provides the capability to close the containment following a loss of another safety function. Thus, the response time for this

safety function is decreased by the decreased response time for the other safety functions. Maintaining an adequate defense-in-depth for this safety function at all times, via the Shutdown Safety Administrative Procedure, minimizes the impact of this decreased response time. Administrative containment closure controls are required to be implemented during fuel movement or whenever the calculated time to RCS boiling is less than 60 minutes.

Spent Fuel Pool Cooling - Section 9.9 of the EPULR notes that the spent fuel cooling systems were evaluated with consideration of EPU. Under normal and abnormal conditions, the fuel pool water temperature does not exceed limits associated with the pool structure, liner, cooling system, or system components.

3. Will changes affect shutdown equipment reliability?

Existing component monitoring programs will detect any additional equipment wear as a result of EPU. While the EPU may result in some components being refurbished or replaced more frequently, the functionality and reliability of components will be maintained to the current standard.

4. Will changes affect availability of equipment or instrumentation used for contingency plans?

Existing component monitoring programs, as discussed in Section 10 of the EPULR, will account for any additional equipment wear as a result of EPU. While the EPU may result in some components being refurbished or replaced more frequently, the functionality and availability of equipment or instrumentation used for contingency plans will be maintained to the current standard.

The NRC staff finds that the licensee's qualitative assessment of shutdown risks associated with the proposed EPU is reasonable because it meets Section IV.4 of Chapter 19 of the SRP. Specifically, the licensee has demonstrated that:

- Suitably redundant and diverse plant response capability is maintained for significant initiators during shutdown modes, and
- Sufficient elements of the plant response capability are subject to programmatic activities to ensure suitable performance.

Therefore, the NRC staff concludes there are no issues concerning shutdown operations that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

Conclusion

The NRC staff has reviewed the licensee's assessment of the risk implications associated with the implementation of the proposed EPU and concludes that the licensee has adequately modeled and/or addressed the potential impacts associated with implementation of the proposed EPU. The staff further concludes that the results of the licensee's risk analysis indicate that the risks associated with the proposed EPU are acceptable and do not create the "special circumstances" described in Appendix D of SRP Chapter 19. In addition, the staff notes that any changes in plant performance that could impact risk (e.g., initiating event

frequencies or component failure rates) following implementation of the proposed EPU would be identified and tracked under the licensee's existing performance monitoring programs and processes (e.g., the Maintenance Rule program). Therefore, the staff finds the risk implications of the proposed EPU to be acceptable.

3.0 FACILITY OPERATING LICENSE AND TS CHANGES

To achieve the EPU, the licensee proposed the following changes to the Facility Operating License and TSs for BVPS-1 and 2.

3.1 Operating License changes:

License Condition 2.C(1) Maximum Power Level.

The licensee proposed to change the maximum reactor core power level from 2689 MWt to 2900 MWt.

The licensee proposed to change the steady state reactor core power level from 2689 MWt to 2900 MWt. The change reflects the actual value in the proposed application and is consistent with the results of the licensee's supporting safety analyses. The NRC staff finds this proposed change acceptable.

License Condition 2.C(2) Technical Specifications

The licensee requests that the amendment number field in License Condition 2.C(2) be left blank for all future amendments.

The purpose of placing the latest amendment number in this License Condition is to reflect the most current amendment to Appendix A of the License. The alternative approach proposed by the licensee deviates from the standard convention used by the NRC for updating and maintaining its authority files of the current license and TSs. This change is not approved as part of this licensing action and will be addressed in a separate licensing action.

3.2 Technical Specification (TS) changes:

Some changes are required for the EPU and others are not EPU-related.

EPU-related

a. DEFINITIONS - 1.3 RATED THERMAL POWER

The proposed change is applicable to both units. The licensee proposed to change the maximum value of RTP from 2689 MWt to 2900 MWt consistent with license Condition 2.C(1). It also allows the specification of an interim RTP in the Licensing Requirements Manual. The change reflects the actual value in the proposed application and is consistent with the results of the licensee's supporting safety analyses. The NRC staff finds this proposed change acceptable.

b. TS 2.1.1.1 SAFETY LIMITS - REACTOR CORE

The proposed change is applicable to both units. The licensee proposed to specify the DNBR for 2 different DNB correlations. For V5H fuel assemblies, the correlation is WRB-1 and the DNBR is maintained $ 1.17. For RFA fuel assemblies, the correlation is WRB-2M and the DNBR is maintained $ 1.14. A reference to a revised thermal design procedure and the correlations is added to the Bases. TS 6.9.5 is also modified to add WCAP-15025-P-A, "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids," to the list of approved methodologies.

The NRC staff has evaluated this change and determined that this change is acceptable. The staff has reviewed and approved the supporting analysis and the proposed changes are consistent with that analysis. The proposed change is supported by the requirements of accepted DNB correlations.

c. TS 3.1.2.8 REFUELING WATER STORAGE TANK (RWST)

The proposed change is applicable to both units. The proposed change would raise the maximum RWST solution temperature to 65 EF for both units.

The NRC staff reviewed the effect of the increased RWST temperature on ECCS NPSH and piping analysis in the SE accompanying Amendment Nos. 271 and 153 issued on February 6, 2006 (ADAMS Accession No. ML060100325). The revised temperature supports adequate containment depressurization capability, and is consistent with the licensee's EPU analyses. Therefore, the proposed change is acceptable.

d. TS 3.3.1.1 REACTOR TRIP SYSTEM INSTRUMENTATION (Tables 3.3-1 and 4.3-1, Functional Unit 4, Power Range, Neutron Flux High Negative Rate Trip)

The proposed change is applicable to both units. The proposed change consists of deleting this item from the tables.

The NRC staff has determined that deleting this item is acceptable since this trip function is not relied upon in any accident analysis in the licensing basis.

e. TS 3.3.1.1 REACTOR TRIP SYSTEM INSTRUMENTATION (Table 3.3-1 Functional Unit 14, Steam Generator Water Level Low-Low)

The propose change is applicable to BVPS-1 only. It consists of revising the value for Functional Unit 14, to reflect the RSGs.

This change was withdrawn by the licensee's letter of February 22, 2006 (Reference 62), as it was approved in Amendment No. 273 (ADAMS Accession No. ML053550053).

f. REACTOR TRIP SYSTEM INSTRUMENTATION (Table 3.3-1, Table Notation, Overtemperature/Overpower ΔT)

The proposed change is applicable to BVPS-1 only. It consists of modifying the equations and a corresponding change to the Bases.

This change was withdrawn by the licensee's letter of February 22, 2006, as it was approved in Amendment No. 273.

g. REACTOR TRIP SYSTEM INSTRUMENTATION (Table 3.3-1, Table Notation, Action 8)

The proposed change is applicable to BVPS-1 only. It consists of changing the permissive in Action 8 from P-7 to P-9.

The licensee stated that when BVPS-1 was originally licensed in 1976, a turbine trip caused a direct reactor trip when operating above P-7. Amendment No. 62, approved on January 26,1983, authorized changing the reactor trip on turbine trip from P-7 to P-9. However, the licensee's LAR failed to request changing from P-7 to P-9 for Action 8 of Table 3.3-1. Action 8 of Table 3.3-1 for BVPS-2 correctly references P-9 as permissive associated with the turbine trip. The proposed change is consistent with Amendment No. 62, corrects an inconsistency between the units and is, therefore, acceptable to the NRC staff.

h. TS 3.3.2.1 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION (Table 3.3-3, Functional Units 5.a, Steam Generator Water Level High-High, and 7.a Steam Generator Water Level Low-Low)

The proposed change is applicable to BVPS-1 only. It consists of revising the values to reflect the RSGs.

This change was withdrawn by the licensee's letter of February 22, 2006, as it was approved in Amendment No. 273.

i. TS 3.4.1.3 REACTOR COOLANT SYSTEM - SHUTDOWN (SR 4.4.1.3.3)

The propose change is applicable to BVPS-1 only. It consists of revising the SG secondary side level requirement of SR 4.4.1.3.3 from 12 percent to 28 percent, to reflect the RSGs.

This change was withdrawn by the licensee's letter of February 22, 2006, as it was approved in Amendment No. 273.

j. TS 3.4.3 REACTOR COOLANT SYSTEM - SAFETY VALVES

The proposed change is applicable to both units. The proposed change consists of changing the positive tolerance for the pressurizer code safety valves from +1 percent to +3 percent for BVPS-1 and from +1 percent to +1.6 percent for BVPS-2.

This change is acceptable to the NRC staff since it is supported by the results of the affected accident analyses presented in the EPULR.

k. TS 3.4.5 STEAM GENERATORS

The proposed change is applicable to both units. The proposed changes for BVPS-1 consist of removing references to SG tube repair and sleeving.

This change was withdrawn by the licensee's letter of February 22, 2006, as it was approved in Amendment No. 273.

The proposed change for BVPS-2 consists of changing the revision number of WCAP-13483, "Beaver Valley Units 1 and 2 Westinghouse Series 51 Steam Generator Sleeving Report, Laser Welded Sleeve," from Revision 1 to Revision 2. The proposed change also changes the repair limit for TIG-welded SG sleeves.

The NRC staff has reviewed the licensee's justification in Section 4.7.2.4.6 of the EPULR and determined that the revised analysis for laser-welded sleeves demonstrates adequate structural integrity and acceptability of primary stress limits, maximum range of stress intensity and fatigue, and minimum wall thickness requirements at EPU conditions. For TIG-welded sleeves, the licensee's justification in Section 4.7.2.4.7 of the EPULR demonstrates that the revised repair limit for the TIG-welded sleeves provides adequate structural integrity. These changes are acceptable for operation at EPU conditions. Therefore, this change is acceptable to the NRC staff.

l. TS 3.4.8 REACTOR COOLANT SYSTEM - SPECIFIC ACTIVITY

The proposed change is applicable to BVPS-1 only. The proposed change consists of revising the primary side coolant activity to reflect the RSGs. This change is reflected in the TS Bases. This change is evaluated in Section 2.9.8 of this SE and is acceptable.

m. TS 3.5.1 ACCUMULATORS

The propose change is applicable to both units. It consists of revising the limits on the accumulator water volume and nitrogen cover pressure. It also consists of replacing the word "contained" with "usable" in SR 4.5.1.a.1. The last part of

the change consists of adding the minimum and maximum accumulator volumes in percent indicated level in addition to gallons.

This change was withdrawn for BVPS-1 by the licensee's letter of February 22, 2006, as it was approved in Amendment No. 273.

For BVPS-2, this change is acceptable, as it is supported by the results of the affected accident analysis which have been reviewed and found acceptable by the NRC staff in this SE.

n. TS 3.5.5 (BVPS-1) and TS 3.5.4 (BVPS-2) SEAL INJECTION FLOW

The propose change is applicable to both units. It consists of raising the minimum value of the charging pump discharge pressure for RCP seal injection flow. The proposed change is reflected in the Bases.

This change was withdrawn for BVPS-1 by the licensee's letter of February 22, 2006, as it was approved in Amendment No. 273.

For BVPS-2, the purpose of this change is to increase the analytical resistance used for the seal injection flow for EPU conditions. The NRC staff reviewed the licensee's analysis in Section 9.2.3 of the EPULR and finds that the proposed change is supported by the accident analysis at EPU conditions supporting the modifications proposed for the CVCS and is therefore, acceptable.

o. TS 3.7.1.1 TURBINE CYCLE - MAIN STEAM SAFETY VALVES (MSSVs)

The propose change is applicable to both units. It consists of changing the maximum percent of RTP in action "a," from 61 percent to 57 percent. Changes are also proposed for the maximum allowable power column of Table 3.7-1, and changing the lift setting tolerances of the MSSVs.

The NRC staff has reviewed the proposed changes and determined that they are supported by the results of the affected accident analysis which was reviewed and found acceptable by the staff in this SE, and are therefore, acceptable.

p. TS 3.7.1.3 PRIMARY PLANT DEMINERALIZED WATER (PPDW)

The propose change is applicable to both units. It consists of replacing the word "contained" with "usable" in the BVPS-1 LCO, revising the BVPS-1 action statement to be consistent with BVPS-2, changing the minimum volume for both units, and relocating a BVPS-2 footnote to the Bases. The Bases are also revised to provide consistency between units.

The NRC staff has reviewed the change to the PPDW minimum level and determined that it is supported by the results of the affected accident analyses approved by the staff in this SE. Therefore, this change is acceptable. The other changes are considered administrative in nature and are acceptable.

q. TS 3.7.1.4 PLANT SYSTEMS - ACTIVITY

The proposed change is applicable to BVPS-1 only. The proposed change consists of revising the value of the secondary side coolant system specific activity. This change is the result of change "l" above.

This change is evaluated in Section 2.9.8 of this SE and is acceptable.

r. TS 6.9.5 CORE OPERATING LIMITS REPORT (COLR)

The propose change is applicable to both units. It consists of adding WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," to the list of NRC-approved methodologies in TS 6.9.5.

This change was withdrawn for BVPS-1 by the licensee's letter of February 22, 2006, as it was approved in Amendment No. 273.

For BVPS-2, this change is consistent with references made in the licensee's supporting accident analyses and is considered administrative in nature, and therefore, acceptable.

Not EPU-related

a. TS 3.3.2.1 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION (Table 3.3-3, Footnote to Steamline Pressure - Low)

The proposed change is applicable to BVPS-1 only. It consists of adding a footnote to all references to Steamline Pressure Low in Table 3.3-3 which provides information on the time constants utilized in the lead-lag controllers for Steamline Pressure - Low.

The NRC staff has reviewed this change and determined that it is within the values specified in Table 5.3.1-3A and 5.6.2-4 of the EPULR, is within the assumptions assumed in the accident analyses, and is otherwise requested to achieve consistency with the associated BVPS-2 TS. Therefore, the proposed change is acceptable.

b. TS 3.5.4.1.1 BORON INJECTION TANK (BIT) $ 350 EF

The proposed change is applicable to BVPS-1 only. The proposed change consists of deleting TS 3.5.4.1.1. This is reflected in the TS Bases.

This change is acceptable because the BIT was not credited as a source of borated water in the EPU accident analysis.

c. TS 3.5.4.1.2 BORON INJECTION TANK # 350 EF, TS 3.5.2 ECCS SUBSYSTEMS - T_{avg} ≥ 350 EF, TS 3.5.3 ECCS SUBSYSTEMS - T_{avg} # 350 EF

The proposed change is applicable to BVPS-1 only. The proposed change consists of renaming and renumbering TS 3.5.4.1.2 to TS 3.5.4, "HHSI FLOW PATH." The Applicability is also changed to match TS 3.4.9.3, "REACTOR COOLANT SYSTEM OVERPRESSURE PROTECTION SYSTEM." A note (2) is added to TS 3.5.2 to allow the HHSI flow path to be isolated when transitioning in or out of the applicability of TS 3.5.4. The change to TS 3.5.3 is to add surveillance requirements from TS 3.5.2 that are applicable to TS 3.5.3. The TS Bases are changed to reflect these changes.

Based on the approval of the TS change in "b" above, these changes are considered administrative in nature, and are acceptable to the NRC staff.

4.0 REGULATORY COMMITMENTS

The licensee has made the following regulatory commitments, which have been or will be completed prior to or concurrent with the EPU amendment implementation or as noted in the individual commitments as "scheduled completion." In the case of Commitment Nos. 6 and 10, prior to a power level increase on BVPS-1 and prior to a power increase above 3 percent for BVPS-2, concurrent with the power level increase for Commitment No. 13, and prior to power ascension testing for BVPS-1 for Commitment No. 22:

1. Incorporate the specific analyses required by WCAP-11394-P-A into the Core Reload Safety Analysis for BVPS-1 and 2 ([8], Attachment D, Commitment No. 1) (BVPS-1 is complete).

2. Implement LAR 317 and 190 (containment conversion to atmospheric operating conditions per License Amendment Nos. 271 and 153) ([8], Attachment D, Commitment No. 2) (BVPS-1 is complete).

3. Implement LAR 318 and 191 (BELOCA methodology per License Amendment Nos. 272 and 154) ([8], Attachment D, Commitment No. 3) (BVPS-1 is complete).

4. Replace the BVPS-1 SGs with Westinghouse Model 54F RSGs, including replacement of level transmitters (per License Amendment No. 273) ([8], Attachment D, Commitment No. 4) (complete).

5. Modify the charging pumps by replacing rotating assemblies and extending the pump runout limit ([8], Attachment D, Commitment No. 5) (BVPS-1 is complete).

6. Modify the main feedwater flow control valve internals ([8], Attachment D, Commitment No. 6, as updated per [59], Attachment 3) (BVPS-1 is complete).

7. Replace or modify the BVPS-1 Overpower ΔT and Overtemperature ΔT instrumentation to incorporate lead/lag filters that accommodate the EPU time constants ([8], Attachment D, Commitment No. 7 for BVPS-1) (complete).

8. Modify the BVPS-2 SGs by removing tubes requiring preventative action from service ([8], Attachment D, Commitment No. 8 for BVPS-2).

9. Resolve the BVPS-1 SG tube rupture event single failure issue by further analysis or by making a plant modification ([8], Attachment D, Commitment No. 9) (complete).

10. Replace the main steam flow and main feedwater flow transmitters ([8], Attachment D, Commitment No. 10, as updated per [59], Attachment 3)(BVPS-1 is complete).

11. Update the operating procedures and conduct operator training ([8], Attachment D, Commitment No. 11).

12. Quantitatively evaluate the impact of EPU changes on PRA results ([8], Attachment D, Commitment No. 12) (complete)

13. Conduct power ascension testing ([8], Attachment D, Commitment No. 13, as updated per [59], Attachment 3).

14. Submit the information requested in Section 2.0 - Probabilistic Safety Review of the enclosure to the NRC acceptability review letter dated January 6, 2005 ([60], Attachment A) (complete).

15. Conduct a piping analysis accounting for a water solid discharge through the pressurizer safety and relief valves during a spurious safety injection event under EPU conditions for BVPS-1 ([10], Enclosure 3, Commitment No. 1) (complete).

16. Conduct a piping analysis accounting for a water solid discharge through the pressurizer safety and relief valves during a spurious safety injection event under EPU conditions for BVPS-2 ([10], Enclosure 3, Commitment No. 1) (complete).

17. As required by the FENOC design modification process, appropriate BVPS-2 turbine overspeed analysis will be performed to ensure overspeed protection is acceptable ([61], Enclosure 3, Commitment No. 1) (Scheduled completion: prior to placing the modified BVPS-2 turbine in service).

18. FENOC is currently an active participant in the EPRI MRP research initiatives on aging-related degradation of reactor vessel internals components, and commits to the following:

    a. Continue its active participation in the MRP initiative to determine appropriate reactor vessel internals degradation management programs,

    b. Evaluate the recommendations resulting from this initiative and implement a reactor vessel internals degradation management program applicable to BVPS-1 and 2, and

    c. Incorporate the resulting reactor vessel internals inspections into the BVPS-1 and 2 augmented inspection program, as appropriate ([61], Enclosure 3, Commitment No. 2) (Scheduled completion: Prior to implementation of the RVIs inspection program per MRP initiatives).

19. Revise the BVPS-2 UFSAR to reflect compliance with 10 CFR 50.68(b) ([17], Enclosure 6, Commitment List) (Scheduled completion: UFSAR update due no later than 6 months following BVPS-2 refueling outage restart).

20. Incorporate the paragraphs provided in the Conclusion Section of Enclosure 1 of FENOC letter L-05-198 into the BVPS-1 Bases for the AFW System TS ([18], Enclosure 3, Commitment No. 1) (complete).

21. Incorporate the paragraphs provided in the Conclusion Section of Enclosure 1 of FENOC letter L-05-198 into the BVPS-2 Bases for the AFW System TS ([18], Enclosure 3, Commitment No. 2).

22. The Power Ascension Test Plan will be approved and implemented prior to power ascension for BVPS-1. The plan will include provisions for recording and analyzing data at each power incremental increase (as noted in Figure 1 of L-06-035) to confirm that the response is as expected and the acceptance criteria are met ([59], Attachment 3, Commitment No. 1 for BVPS-1).

23. The Power Ascension Test Plan will be approved and implemented prior to power ascension for BVPS-2. The plan will include provisions for recording and analyzing data at each power incremental increase (as noted in Figure 2 of L-06-035) to confirm that the response is as expected and the acceptance criteria are met ([59], Attachment 3, Commitment No. 1 for BVPS-2).

24. The BVPS-2 boron dilution accident analysis requires operator action for mitigation of the event, and the BVPS-2 licensing basis (RG 1.70, Revision 3, and the SRP) includes consideration for 15-minute notification to the operator. This operator notification time needs to be included in the boron dilution accident analysis calculation. The licensee will include this 15-minute notification time in the analysis the next time the boron dilution analysis calculation is updated ([17], Enclosure 4).

The NRC staff finds that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitments are best provided by the licensee’s administrative processes, including its commitment management program. The above regulatory commitments do not warrant the creation of regulatory requirements (items requiring prior NRC approval of subsequent changes).

5.0 RECOMMENDED AREAS FOR INSPECTION

As described above, the NRC staff has conducted an extensive review of the licensee's plans and analyses related to the proposed EPU and concluded that they are acceptable. The NRC staff’s review has identified the following areas for consideration by the NRC inspection staff during the licensee's implementation of the proposed EPU. These areas are recommended based on past experience with EPUs, the extent and unique nature of modifications necessary to implement the proposed EPU, and new conditions of operation necessary for the proposed EPU. They do not constitute inspection requirements, but are intended to give inspectors insight into important bases for approving the EPU.

1. Steam generator replacement activities (BVPS-1 only)

2. Power ascension testing activities

3. BVPS-2 HP turbine modifications and testing

6.0 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.

7.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, 51.33, and 51.35, a draft Environmental Assessment and finding of no significant impact was prepared and published in the *Federal Register* on May 9, 2006 (71 FR 26985). The draft Environmental Assessment provided a 30-day opportunity for public comment. No comments were received on the draft Environmental Assessment. The final Environmental Assessment was published in the *Federal Register* on July 14, 2006 (71 FR 40162). Accordingly, based upon the environmental assessment, the Commission has determined that the issuance of this amendment will not have a significant effect on the quality of the human environment.

8.0 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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

9.0 REFERENCES

[1] RS-001, Revision 0, "Review Standard for Extended Power Uprates," December 2003 (ADAMS Accession No. ML033640024).
[2] NUREG-0800, "Standard Review Plan," Draft Revision, April 1996
[3] Updated Final Safety Analysis Reports, Revisions 22 and 15, respectively, for Beaver Valley Power Station, Unit Nos. 1 and 2.
[4] NRC letter to FENOC, "Beaver Valley Power Station, Unit Nos. 1 and 2 (BVPS-1 and 2) - Issuance of Amendment Nos. 271 And 153 Re: Containment Conversion from Subatmospheric to Atmospheric Operating Conditions," February 6, 2006.
[5] FENOC Letter L-05-069, Beaver Valley Power Station Unit 1, to NRC, "License Amendment Request 320," dated April 13, 2005.
[6] NRC letter to FENOC, "Beaver Valley Power Station, Unit No. 1 (BVPS-1) - Issuance of Amendment No. 273 Re: Steam Generator (SG) Replacement," February 9, 2006
[7] WCAP-7907-P-A, "LOFTRAN Code Description," April 1984.
[8] FENOC Letter L-04-125, Beaver Valley Power Station, Units No. 1 and No. 2, "License Amendment Request Nos. 302 and 173," October 4, 2004.
[9] FENOC Letter L-05-078, Beaver Valley Power Station, Units No. 1, and No. 2, "Responses to a Request for Additional Information in Support of License Amendment Request Nos. 302 and 173," May 26, 2005.

[10] FENOC Letter L-05-112, Beaver Valley Power Station, Units No. 1 and No. 2, “License Amendment Request Nos. 302 and 173," July 8, 2005.

[11] FENOC Letter L-05-140, Beaver Valley Power Station, Units No. 1 and No. 2, “Response to a Request for Additional Information (RAI dated August 2, 2005) in Support of License Amendment Request Nos. 302 and 173, Extended Power Uprate,” September 6, 2005.

[12] FENOC Letter L-05-154, Valley Power Station, Units No. 1 and No. 2, “Supplemental Information for License Amendment Request Nos. 302 and 173," October 7, 2005.

[13] Audit of the BVPS Unit 1 RSG program at the Monroeville, PA offices of Westinghouse, November 7 - 9, 2005 (EPU topics were also addressed at that time).

[14] FENOC Letter L-05-165, Beaver Valley Power Station, Unit No. 1, “Response to a Request for Additional Information (RAI dated September 28, 2005) in Support of License Amendment Request No. 320," November 18, 2005

[15] FENOC Letter L-05-168, Beaver Valley Power Station, Units No. 1 and No. 2, “Supplement to License Amendment Request Nos. 320 and 302/173," October 28, 2005.

[16] FENOC Letter L-05-169, Beaver Valley Power Station, Units No. 1 and No. 2, “Responses to a Request for Additional Information (RAI dated September 30, 2005) in Support of License Amendment Request Nos. 302 and 173," November 21, 2005.

[17] FENOC Letter L-05-177, Beaver Valley Power Station, Units No. 1 and No. 2, “Responses to a Request for Additional Information (RAI dated November 1, 2005) in Support of License Amendment Request Nos. 302 and 173," December 2, 2005.

[18] FENOC Letter L-05-198, Beaver Valley Power Station, Units No. 1 and No. 2, “Supplemental Information for License Amendment Request Nos. 320 and 302/173," December 16, 2005.

[19] WCAP-15571, Revision 0, “Analysis of Capsule Y from the FirstEnergy Nuclear Operating Company Beaver Valley Unit 1 Reactor Vessel Radiation Surveillance Program,” Westinghouse Electric Company LLC, by C. Brown, et al., November 2000.

[20] WCAP-15570, Revision 0, “Beaver Valley Unit 1 Heatup and Cooldown Limit Curves for Normal Operation,” Westinghouse Electric Company LLC, by C. Brown and E. Terek, November 2000.

[21] WCAP-15675, “Analysis of Capsule W from the FirstEnergy Nuclear Operating Company Beaver Valley Unit 2 Reactor Vessel Radiation Surveillance Program,” Westinghouse Electric Company LLC, by J. H. Ledger, et al., August 2001.

[22] WCAP-15677, “Beaver Valley Unit 2 Heatup and Cooldown Limit Curves for Normal Operation,” Westinghouse Electric Company LLC, by J. H. Ledger, et al., August 2001.

[23] WCAP-15569, Revision 0 “Evaluation of Pressurized Thermal Shock for Beaver Valley Unit 1,” Westinghouse Electric Company LLC, by C. Brown and E. Terek, November 2000.

[24] WCAP-15676, “Evaluation of Pressurized Thermal Shock for Beaver Valley Unit 2,” Westinghouse Electric Company LLC, by J. H. Ledger, et al., August 2001.

[25] Letter from S. A. Varga, NRC to J. J. Carey, Duquesne Light Company, “Beaver Valley Power Station, Unit 1, Request for Exemption from Some Requirements of Appendix R to 10 CFR Part 50," March 14, 1983.

[26] WCAP-10698-P-A, SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill,” issued August 1985 and WCAP-11002, “Evaluation of Steam Generator Overfill Due to a Steam Generator Tube Rupture Accident,” issued February 1986.

[27] WCAP-11397-P-A, Revised Thermal Design Procedure, A. J. Friedland and S. Ray, April 1989.
[28] WCAP-12610-P-A, “VANTAGE+ Fuel Assembly Reference Core Report,” April 1995.
[29] Letter from Donald S. Brinkman (USNRC) to J. E. Cross, Duquesne Light Company, re: “Beaver Valley Power Station, Unit Nos. 1 and 2 (TAC Nos. M98141 AND M98142),” dated May 23, 1997 (ADAMS Accession No. ML003768579).
[30] Letter from Donald S. Brinkman (USNRC) to J. E. Cross, Duquesne Light Company, re: “Beaver Valley Power Station, Unit No. 2 (TAC NO. M95319),” dated September 13, 1996 (ADAMS Accession No. ML003772500).
[31] WCAP-12488-P-A, “Westinghouse Fuel Criteria Evaluation Process,” October 1994.
[32] FCEP Notification for the RFA fuel design dated September 30, 1998.
[33] FCEP Notification for the RFA-2 fuel design dated August 31, 2001.
[34] WCAP-10851-P-A, “Improved Fuel Performance Models for Westinghouse fuel Rod Design and Safety Evaluations,” (PAD 3.4),” Dated August 1988.
[35] WCAP-15063-P-A, Revision 1, with Errata (Proprietary), “Westinghouse Improved Performance Analysis and Design Model (PAD 4.0),” J. P. Foster and S. Sidener, July 2000.
[36] NRC letter from S. Richards to H. A. Sepp (Westinghouse), “Safety Evaluation Related to Topical Report,” WCAP-15063, Revision 1, “Westinghouse Improved Performance Analysis and Design Model (PAD 4.0),” (TAC No. MA2086), April 24, 2000.
[37] NRC letter, “Beaver Valley Power Station, Units Nos. 1 and 2 (BVPS-1 and 2) - Issuance of Amendment Nos. 274 and 155, re: Relaxed Axial Offset Control (RAOC) and FQ Surveillance Methodologies (TAC Nos. MC5904 and MC5905),” dated February 27, 2006 (ADAMS Accession No. ML060330636).
[38] WCAP-10216-P-A, "Relaxation of Constant Axial Offset Control/FQ Surveillance Technical Specification," Revision 1, February 1994
[39] American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section III, “Nuclear Power Plant Components,” Article NB-7000, “Protection Against Overpressure.”
[40] ANS 51.1, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants,” 1983.
[41] WCAP-11394-P-A, “Methodology for the Analysis of the Dropped Rod Event,” January 1990.
[42] WCAP-9272-P-A, “Westinghouse Reload Safety Evaluation Methodology,” S. L. Davidson, (Ed.), July 1985
[43] WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999.
[44] NRC Safety Evaluation Report, "Acceptance for Referencing of Licensing Topical Report WCAP-14565, VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis (TAC NO. M98666)," January 19, 1999.
[45] WCAP-9230 (Proprietary) and WCAP-9231 (Non-proprietary), “Report on the Consequences of a Postulated Main Feedline Rupture,” January 1978.
[46] WCAP-10965-P-A, “ANC: A Westinghouse Advanced Nodal Computer Code,” September 1986.
[47] USNRC letter from Carl Berlinger to E. P. Rahe, Westinghouse, accepting the ANC code, dated June 23, 1986.
[48] ANSI/ANS-5.1-1979, “American National Standard for Decay Heat Power in Light Water Reactors,” August 1979.

[49] NRC Regulatory Issue Summary 2005-29, “Anticipated Transients That Could Develop Into More Serious Events,” dated December 14, 2005 (ADAMS Accession No. ML051890212).

[50] WCAP-12945-P-A, Volume 1 (Revision 2) 1996 and Volumes 2 through 5 (Revision 1), “Code Qualification Document for Best Estimate LOCA Analysis, March 1998" (CQD methodology).

[51] NS-TMA-2182, letter from T. M. Anderson, Westinghouse, to S. H. Hanauer, NRC, “ATWS Submittal,” dated December 30, 1979.

[52] EPRI NP-2770-LD, Volume 8, Interim Report, EPRI/C-E PWR Safety Valve Test Report – Test Results for Target Rock Safety Valve, March 1983.

[53] EPRI NP-2770-LD, Volume 9, Interim Report, EPRI/C-E PWR Safety Valve Test Report – Test Results for Crosby/Framatome Safety Valve with Assisted Device, March 1983.

[54] WCAP-11677, “Pressurizer Safety Valve Relief Valve Operation for Water Discharge During a Feedwater Line Break,” January 1988.

[55] M. A. Mangan, "Overpressure Protection for Westinghouse Pressurized Water Reactors," WCAP-7769, Westinghouse Electric Corporation (October 1971).

[56] FENOC Letter L-06-003 Letter from James H. Lash, FENOC, to USNRC Document Control Desk, re: “Beaver Valley Power Station, Unit Nos. 1 and 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Additional Information in Support of License Amendment Request, Nos. 302 and 173 (Unit No. 1 TAC No. MC4645/Unit No. 2 TAC No. MC4646),” dated January 25, 2006. (ADAMS Accession No. ML060330262).

[57] NRC Issuance of Amendment Nos. 257 And 139, Letter dated September 10, 2003, Beaver Valley Power Station, Unit Nos. 1 and 2.

[58] WCAP-7588; Rev. 1A, “An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors using Special Kinetics Methods,” Risher, D. H., January 1975.

[59] FENOC Letter L-06-035, “Beaver Valley Power Station, Unit Nos. 1 and 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Supplemental Information - EPU Implementation Plan & Power Ascension Testing: License Amendment Request Nos. 302 and 173," dated March 10, 2006.

[60] FENOC Letter L-05-026, “Beaver Valley Power Station, Unit Nos. 1 and 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Supplemental Information Supporting License Amendment Request Nos. 302 and 173," dated February 23, 2005.

[61] FENOC Letter L-05-173, “Beaver Valley Power Station, Unit Nos. 1 and 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Additional Information Regarding License Amendment Request Nos. 302 and 173 - Extended Power Uprate (EPU)," dated November 8, 2005.

[62] FENOC Letter L-05-104, “Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Probabilistic Safety review for License Amendment Request Nos. 302 and 173,” dated June 14, 2005.

[63] FENOC Letter L-05-192, “Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Supplemental PRA Information in Support of License Amendment Request Nos. 302 and 173, Extended Power Uprate (EPU),” dated December 9, 2005.

[64] FENOC Letter L-06-018, “Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-

73, Supplemental Response in Support of License Amendment Request Nos. 302 and 173 (Unit No. 1 TAC No. MC4645/Unt No. 2 TAC No.MC4646)," dated February 14, 2006.

[65] USNRC letter from Timothy G. Colburn to L. William Pearce, FENOC, re: "Beaver Valley Power Station, Units Nos. 1 and 2 - Issuance of Amendment re: Increase of the Emergency Diesel Generator (EDG) Allowed Outage Time From 72 Hours to 14 Days (TAC Nos. MC3331 and MC3332)," dated September 29, 2005.

[66] FENOC Letter L-04-141,"Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73; Response to Request for Additional Information in Support of LAR Nos. 306 and 176; Emergency Diesel Generator Allowed Outage Time Extension," dated October 29, 2004.

[67] NRC "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," NUREG-0800, Section 19, Revision 1, November 2002.

[68] American Society for Mechanical Engineers, "Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications," ASME RA-Sb-2005, December 20, 2005

[69] NRC "Regulatory Guide 1.174, Revision 1, "An Approach to Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," November 2002.

[70] FENOC Letter L-05-026, "Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Supplemental Information Supporting License Amendment Request Nos. 302 and 173," dated February 23, 2005.

[71] FENOC Letter L-05-130, "Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Responses to a Request for Additional Information (RAI Dated June 30, 2005) in Support of License Amendment Request Nos. 302 and 173," dated July 28, 2005.

[72] FENOC Letter L-05-137, "Beaver Valley Power Station, Unit No. 1, BV-1 Docket No. 50-334, License No. DPR-66, Responses to a Request for Additional Information (RAI Dated July 28, 2005) in Support of License Amendment Request No. 320," dated August 26, 2005.

[73] FENOC Letter L-05-163, "Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Supplement to License Amendment Request Nos. 327/197 (Unit No. 1 TAC No. MC4649/Unit No. 2 TAC No. MC4650), 317/190 (Unit No. 1 TAC No. MC3394/Unit No. 2 TAC No. MC3395), and 320 (Unit No. 1 TAC No. MC6725)," dated October 31, 2005.

[74] FENOC Letter L-05-195, "Beaver Valley Power Station, Unit No. 1, BV-1 Docket No. 50-334, License No. DPR-66, Additional Information Regarding Responses to RAI Dated July 28, 2005, in Support of License Amendment Request No. 320," dated December 6, 2005.

[75] FENOC Letter L-05-204, "Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Additional Information Regarding Dose consequence Analysis in Support of License Amendment Request Nos. 302 and 173," dated December 30, 2005.

[76] FENOC Letter L-06-025, “Beaver Valley Power Station, Unit No. 1, BV-1 Docket No. 50-334, License No. DPR-66, Supplemental Information Pertaining to License Amendment Request No. 302 (TAC No. MC4649),” dated February 22, 2006.

[77] FENOC Letter L-06-083, “Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, Supplemental Information in Support of License Amendment Request Nos. 302 and 173 (Unit No. 1 TAC No. MC4645 and Unit No. 2 TAC No. MC4646),” dated May 12, 2006.

[78] NRC Issuance of Amendment Nos. 270 and 152, Re: Steam Generator (SG) Allowable Value Setpoints, Beaver Valley Power Station, Unit Nos. 1 and 2, dated January 11, 2006.

[79] NRC Issuance of Amendment Nos. 272 and 154, Re: Applicability of Westinghouse Topical Report “WCAP-12945-O-A, Volume 1, Revision 2, 1996, and Volumes 2-5, Revision 1, ‘Code Qualification Document for Best-Estimate LOCA [BELOCA] Analysis,’ March 1998,” dated February 6, 2006.

Attachment:
List of Acronyms

Principal Contributors:	S. Miranda	F. Orr	K. Wood	C. Liang
	L. Ward	C. Wu	A. Turilin	C. Hammer
	N. Trehan	A. Stubbs	G. Makar	T. Scarbrough
	H. Walker	R. Wolfgang	P. Patnaik	L. Miller
	G. Galletti	S. Laur	L. Lois	S. Klementowicz
	I. Ahmed	J. Lee	L. Brown	R. Lobel
	P. Clifford	V. Klein	J. Medoff	L. Fields
	K. Martin	T. Colburn	R. Pettis	J. Parillo

Date: July 19, 2006

LIST OF ACRONYMS

AAC	alternate ac sources
AC	alternating current
ADAMS	Agencywide Documents Access and Management System
AFW	auxiliary feedwater
ALARA	as low as reasonably achievable
AOO	anticipated operational occurrence
AOP	abnormal operating procedure
AOR	analysis of record
ARAVS	auxiliary and radwaste area ventilation system
ARC	alternate repair criteria
ASME	American Society of Mechanical Engineers
AST	alternative source term
ASTM	American Society for Testing and Materials
ATSI	American Transition Systems Incorporated
ATWS	anticipated transient without scram
AV	allowable value
B&PV	boiler and pressure vessel
B&W	Babcock and Wilcox
BELOCA	best-estimate loss-of-coolant accident
BIT	boron injection tank
BL	bulletin
BLPB	branch line pipe break
BOL	beginning of life
BOP	balance-of-plant
BTP	branch technical position
BVPS	Beaver Valley Power Station
CAP	corrective action process

CAR	containment air recirculation
CASS	cast austenitic stainless steel
CCW	component cooling water
CDF	core damage frequency
CE	Combustion Engineering
CFR	*Code of Federal Regulations*
CHF	critical heat flux
CFS	condensate and feedwater system
CMTR	certified mill test report
COLR	core operating limits report
COMS	cold overpressure mitigation system
CQD	code qualification document
CR	control room
CRAVS	control room area ventilation system
CREA	control rod ejection accident
CREVS	control room emergency ventilation system
CRDM	control rod drive mechanism
CRDS	control rod drive system
CUF	cumulative usage factor
CVCS	chemical and volume control system
CWS	circulating water system
DBA	design-basis accident
DBE	design-basis earthquake
DBLOCA	design-basis loss-of-coolant accident
DC	direct current
DG	draft guide
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
EAB	exclusion area boundary

ECCS	emergency core cooling system
EDG	emergency diesel generator
EFDS	equipment and floor drainage system
EFPY	effective full power years
EOC	end-of-cycle
EOL	end of life
EOP	emergency operating procedure
EPRI	Electric Power Research Institute
EPU	extended power uprate
EPULR	extended power uprate licensing report
EQ	environmental qualification
ERFCS	emergency response facility computer system
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
ESFVS	engineered safety feature ventilation system
FAC	flow-accelerated corrosion
FCEP	fuel criteria evaluation process
FCV	flow control valve
FENOC	FirstEnergy Nuclear Operating Company
FHA	fuel-handling accident
FLB	feedwater line break
FIV	flow-induced vibration
FPP	fire protection program
FRV	feedwater regulating valves
GDC	general design criterion (or criteria)
GL	generic letter
GWMS	gaseous waste management system
HELB	high energy line break
HFP	hot full power

HP	high pressure
HRA	human reliability analysis
HZP	hot zero power
IASCC	irradiation assisted stress-corrosion cracking
IFM	intermediate flow mixing
IN	information notice
IPE	individual plant examination
IPEEE	individual plant examination of external events
ISI	inservice inspection
LAR	license amendment request
LBB	leak-before-break
LBLOCA	large-break loss-of-coolant accident
LCO	limiting condition for operation
LERF	large early release frequency
LLHS	light load handling system
LOCA	loss-of-coolant accident
LOL	loss of load
LONF	loss of normal feedwater
LOOP	loss of offsite power
LPZ	low population zone
LTOP	low temperature overpressure protection
LWMS	liquid waste management system
MAAP	modular accident analysis program
MC	main condenser
MCES	main condenser evacuation system
MCL	main coolant loop
MFIV	main feedwater isolation valve
MOV	motor-operated valve
MPT	main power transformer

MSIV	main steam isolation valve
MSLB	main steam line break
MSR	moisture separator reheater
MSSS	main steam supply system
MSSV	main steam safety valve
MTC	moderator temperature coefficient
MUR	measurement uncertainty recapture
MWt	megawatts thermal
NEI	Nuclear Energy Institute
NPSH	net positive suction head
NR	narrow range
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSSS	nuclear steam supply system
OSG	original steam generator
PCT	peak cladding temperature
PCWG	Power Capability Working Group
P-T	pressure-temperature
PMT	post-modification test
PORV	power-operated relief valve
PPDWST	primary plant demineralized water storage tank
PRA	probabilistic risk assessment
PRT	pressurizer relief tank
PSV	pressurizer safety valve
PSEC	Power Systems Energy Consulting
PTLR	pressure-temperature limits report
PTS	pressurized thermal shock
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking

QA	quality assurance
RAI	request for additional information
RAOC	relaxed axial offset control
RCCA	rod control cluster assembly
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
REA	rod ejection accident
RFA	robust fuel assembly
RG	regulatory guide
RHR	residual heat removal
RIA	reactivity insertion accident
RS	review standard
RSG	replacement steam generator
RTD	resistance temperature detector
RTDP	rated thermal design procedure
RTP	rated thermal power
RTS	reactor trip system
RV	reactor vessel
RVI	reactor vessel internals
RVMSP	reactor vessel material surveillance program
RWS	river water system
RWST	refueling water storage tank
SAFDL	specified acceptable fuel design limit
SAL	safety analysis limit
SAMG	severe accident management guideline
SBLOCA	small-break loss-of-coolant accident
SBO	station blackout
SCC	stress-corrosion cracking

SDM	shutdown margin
SE	safety evaluation
SFP	spent fuel pool
SFPAVS	spent fuel pool area ventilation system
SFPCCS	spent fuel pool cooling and cleanup system
SG	steam generator
SGBS	steam generator blowdown system
SGTR	steam generator tube rupture
SLCRS	supplementary leak collection and release system
SLIM	success likelihood index method
SI	safety injection
SPDS	safety parameter display system
SRP	Standard Review Plan
SSCs	structures, systems, and components
SSE	safe-shutdown earthquake
SSST	system station service transformer
STDP	standard thermal design procedure
SWMS	solid waste management system
SWS	service water system
TAVS	turbine area ventilation system
TBS	turbine bypass system
TCV	turbine control valve
TEDE	total effective dose equivalent
TG	turbine generator
TGSS	turbine gland sealing system
TS	technical specification
UFSAR	Updated Final Safety Analysis Report
UHS	ultimate heat sink
USE	upper shelf energy

USST	unit station service transformer
V5H	Vantage 5H
WGSR	waste gas system rupture