June 27, 2008

Mr. M. R. Blevins
Executive Vice President
& Chief Nuclear Officer
Luminant Generation Company LLC
ATTN: Regulatory Affairs
P. O. Box 1002
Glen Rose, TX 76043

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION, UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS RE: LICENSE AMENDMENT REQUEST 07-004, REVISION TO OPERATING LICENSE AND TECHNICAL SPECIFICATION 1.0, "USE AND APPLICATION," TO REVISE RATED THERMAL POWER FROM 3458 MWT TO 3612 MWT (TAC NOS. MD6615 AND MD6616)

Dear Mr. Blevins:

The U.S. Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 146 to Facility Operating License No. NPF-87 and Amendment No. 146 to Facility Operating License No. NPF-89 for Comanche Peak Steam Electric Station (CPSES), Units 1 and 2, respectively. The amendments consist of changes to the Technical Specifications (TSs) in response to your application dated August 28, 2007, as supplemented by letters dated October 24, November 7, and December 3, 2007, January 10, 29, and 31, February 21, 26, and 28, March 6, April 17, and May 14, 2008.

The amendments authorize CPSES to operate at 3612 megawatts thermal (MWt) and make changes to the TSs to support operation at the higher power level. The licensee's application also requested approval of the spent fuel pool (SFP) criticality analysis and amendments to TS 3.7.17, "Spent Fuel Assembly Storage," in support of the SFP storage requirements. The NRC staff has informed Luminant Generation Company LLC that this part of the amendment request is being reviewed separately under TAC Nos. MD8417 and MD8418.

A copy of our related Safety Evaluation is enclosed. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

/RA/

Balwant K. Singal, Senior Project Manager
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-445 and 50-446

Enclosures:
1. Amendment No. 146 to NPF-87
2. Amendment No. 146 to NPF-89
3. Safety Evaluation

cc w/encls: See next page

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Sincerely,

/RA/

Balwant K. Singal, Senior Project Manager
Plant Licensing Branch IV
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ADAMS Accession Nos.: Pkg ML081510157 (Amendment ML081510173, License/TS Pgs ML081510175)
* SE issued by individual branches on indicated dates ** See previous concurrence *** Via e-mail

OFFICE	NRR/LPL4/PM	NRR/LPL4/LA	DCI/CPNB/BC	DCI/CPTB/BC	DCI/CSGB/BC
NAME	BSingal **	JBurkhardt **	TChan *	JMcHale *	AHiser *
DATE	6/4/08	6/4/08	3/24/08	4/16/08	4/24/08
OFFICE	DCI/CVIB/BC	DE/EEEB/BC	DE/EMCB/BC	DE/EICB/BC	DIRS/IOLB/BC
NAME	MMitchell *	GWilson *	KManoly *	WKemper *	NSalgado *
DATE	3/31/08	5/22/08	5/14/08	3/25/08	5/2/08
OFFICE	DLR/RERB/BC	DRA/AADB/BC	DRA/AFPB/BC	DSS/SBPB/BC	DSS/SCVB/BC
NAME	EBenner *	RTaylor *	AKlein *	DHarrison *	RDennig *
DATE	2/7/08	3/13/08	2/29/08	4/30/08	4/24/08
OFFICE	DSS/SNPB/BC	DSS/SRXB/BC	OGC – no legal objection		NRR/DORL/D
NAME	AMendiola ***	GCranston *	BMizuno **		THiltz
DATE	6/20/08	5/19/08	6/17/08		6/26/08
OFFICE	NRR/DORL/DD	NRR/DORL/D	NRR/LPL4/PM		
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DATE	6/26/08	6/26/08	6/26/08		

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LUMINANT GENERATION COMPANY LLC

COMANCHE PEAK STEAM ELECTRIC STATION, UNIT NO. 1

DOCKET NO. 50-445

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 146
License No. NPF-87

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

   A. The application for amendment by Luminant Generation Company LLC dated August 28, 2007, as supplemented by letters dated October 24, November 7, and December 3, 2007, January 10, 29, and 31, February 21, 26, and 28, March 6, April 17, and May 14, 2008, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

ENCLOSURE 1

2. Accordingly, the license is amended to increase the authorized core power level from 3458 megawatts thermal to 3612 megawatts thermal, and Paragraph 2.C.(1) of Facility Operating License No. NPF-87 is hereby amended to read as follows:

   (1) Maximum Power Level

   Luminant Generation Company LLC is authorized to operate the facility at reactor core power levels not in excess of 3458 megawatts thermal through Cycle 13 and 3612 megawatts thermal starting with Cycle 14 in accordance with the conditions specified herein.

3. In addition, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and Paragraph 2.C.(2) of Facility Operating License No. NPF-87 is hereby amended to read as follows:

   (2) Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A as revised through Amendment No. 146 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. Luminant Generation Company LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan as indicated in the attachment to this license amendment.

4. The license amendment is effective as of its date of issuance and shall be implemented within 180 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Joseph G. Giitter, Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility Operating License
No. NPF-87 and Technical Specifications

Date of Issuance: June 27, 2008

LUMINANT GENERATION COMPANY LLC

COMANCHE PEAK STEAM ELECTRIC STATION, UNIT NO. 2

DOCKET NO. 50-446

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 146
License No. NPF-89

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

   A. The application for amendment by Luminant Generation Company LLC dated August 28, 2007, as supplemented by letters dated October 24, November 7, and December 3, 2007, January 10, 29, and 31, February 21, 26, and 28, March 6, and April 17, and May 14, 2008, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

ENCLOSURE 2

2. Accordingly, the license is amended to increase the authorized core power level from 3458 megawatts thermal to 3612 megawatts thermal, and Paragraph 2.C.(1) of Facility Operating License No. NPF-89 is hereby amended to read as follows:

   (1) Maximum Power Level

   Luminant Generation Company LLC is authorized to operate the facility at reactor core power levels not in excess of 3458 megawatts thermal through Cycle 11 and 3612 megawatts thermal starting with Cycle 12 in accordance with the conditions specified herein.

3. In addition, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and Paragraph 2.C.(2) of Facility Operating License No. NPF-89 is hereby amended to read as follows:

   (2) Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A as revised through Amendment No. 146 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. Luminant Generation Company LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

4. This license amendment is effective as of its date of issuance and shall be implemented within 180 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Joseph G. Giitter, Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility Operating License
No. NPF-89 and Technical Specifications

Date of Issuance: June 27, 2008

ATTACHMENT TO LICENSE AMENDMENT NO. 146

TO FACILITY OPERATING LICENSE NO. NPF-87

AND AMENDMENT NO. 146

TO FACILITY OPERATING LICENSE NO. NPF-89

DOCKET NOS. 50-445 AND 50-446

Replace the following pages of the Facility Operating License Nos. NPF-87 and NPF-89, and Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Facility Operating License No. NPF-87

REMOVE	INSERT
3	3

Facility Operating License No. NPF-89

REMOVE	INSERT
3	3

Technical Specifications

REMOVE	INSERT
1.1-6	1.1.6

ENCLOSURE 3

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NOS. 146 AND 146 TO

FACILITY OPERATING LICENSE NOS. NPF-87 AND NPF-89

LUMINANT GENERATION COMPANY LLC

COMANCHE PEAK STEAM ELECTRIC STATION, UNITS 1 AND 2

DOCKET NOS. 50-445 AND 50-446

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NOS. 146 AND 146 TO

FACILITY OPERATING LICENSE NOS. NPF-87 AND NPF-89

LUMINANT GENERATION COMPANY LLC

COMANCHE PEAK STEAM ELECTRIC STATION, UNITS 1 AND 2

DOCKET NOS. 50-445 AND 50-446

1.0 INTRODUCTION

1.1 Application

By application dated August 28, 2007 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML072490131) (Reference 3), as supplemented by letters dated October 24, November 7, and December 3, 2007, January 10, 29, and 31, February 21, 26, and 28, March 6, April 17, and May 14, 2008 (ADAMS Accession Nos. ML073120098, ML073230080, ML073450847, ML080160118, ML080390320, ML080390311, ML080590356, ML080650370, ML080660070, ML080710410, ML081150509, and ML081420027, respectively) (References 4 through 15, respectively), TXU Generation Company LP (subsequently renamed Luminant Generation Company LLC, the licensee) requested changes to the Facility Operating Licenses and Technical Specifications (TSs) for the Comanche Peak Steam Electric Station (CPSES), Units 1 and 2.

The supplemental letters dated October 24, November 7, and December 3, 2007, January 10, 29, and 31, February 21, 26, and 28, March 6, April 17, and May 14, 2008, provided additional clarifying information that did not expand the scope of the initial application and did not change the Nuclear Regulatory Commission (NRC) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on October 23, 2007 (72 FR 60034).

Each operating CPSES unit was originally designed for a warranted power output of 3411 megawatts thermal (MWt). The rated thermal power for both the CPSES units was subsequently increased to 3458 MWt, which represents a 1.4 percent increase in core output from the original rated thermal power. The proposed changes would increase the maximum steady-state reactor core power level from 3458 MWt to 3612 MWt, which is an increase of approximately 4.5 percent (resulting in cumulative increase of 5.9 percent). The proposed increase in power level is considered a stretch power uprate (SPU).

The license amendment request (LAR) 07-004, submitted under the application dated August 28, 2007 (Reference 3), by the licensee, also contained a report presenting the results

of the criticality safety analysis for Region II of the CPSES, Units 1 and 2 spent fuel pool (SFP) racks, along with revised TS 3.7.17, in addition to the request for the SPU. The licensee agreed that amendment requests associated with SPU and SFP criticality analysis will be processed separately.

1.2 Background

CPSES, Units 1 and 2 are pressurized-water reactor (PWR) plants of the Westinghouse 4-Loop design with a steel-lined, reinforced concrete, cylindrical structure with a hemispherical dome containment designed by Gibbs and Hill, Inc. (Architect Engineers). CPSES, Unit 1 was declared for commercial operation on August 13, 1990, and Unit 2 was declared for commercial operation on August 3, 1993.

CPSES, Units 1 and 2 are located near the town of Glen Rose, Texas about 90 miles southwest of Dallas, Texas. CPSES, Units 1 and 2 are located on Squaw Creek Reservoir near the Brazos River. The site is approximately 8000 acres including the developed portion of the site, which is approximately 3663 acres in size. In addition to the two CPSES reactors, the site includes the Squaw Creek Reservoir and dam.

1.3 Licensee's Approach

The licensee developed this LAR following the guidelines in NRC Review Standard, RS-001, "Review Standard for Extended Power Uprates" (Reference 1). The licensee stated that the LAR expectations of RS-001 extend beyond those historically required for an SPU, but were used to assure completeness of the SPU submittal. 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.

The licensee has taken credit for the following license amendments, already approved by NRC, in support of the SPU submittal:

- License Amendment No. 143 for CPSES, Units 1 and 2, Revision to Technical Requirements Surveillance 13.3.33.2, dated February 29, 2008 (ADAMS Accession No. ML080220107) (Reference 37).

- License Amendment No. 144 for CPSES, Units 1 and 2, Revision to Technical Specifications to Allow the Use of Westinghouse-Developed/NRC-Approved Analytical Methods to Establish Core Operating Limits, dated April 2, 2008 (ADAMS Accession No. ML080500666) (Reference 27).

- License Amendment No. 145 for CPSES, Units 1 and 2, Changes to Technical Specifications to Reflect Cycle-Specific Safety Analysis Assumptions and Results of Adoption of Westinghouse Methodologies, dated April 3, 2008 (ADAMS Accession No. ML080580003) (Reference 28).

The licensee has proposed to implement this amendment during restart from the refueling outage in the fall of 2008 for CPSES, Unit 1 and fall of 2009 for CPSES, Unit 2 and operation at the increased power level will occur in Cycles 14 and 12, respectively.

1.4 Plant Modifications

The licensee has determined that several plant modifications are necessary to implement the proposed SPU. The following is a list of these modifications.

- Make setpoint changes for the reactor trip system (RTS) and the engineered safety features actuation system (ESFAS). However, these setpoint changes have already been incorporated under Amendment No. 145 for CPSES, Units 1 and 2 and no further changes are needed associated with the SPU submittal.

- The CPSES, Units 1 and 2 high-pressure turbines will be replaced in order to pass the additional volumetric steam flow. Turbine digital controls and thyristor voltage regulator settings will be revised for uprate conditions. The low-pressure turbines will not be modified as they are capable of passing the higher volumetric flow rate.

- Higher condensate pump flow rate and additional head loss in the condensate and feedwater piping will result in lower suction pressure at the main feed pump (MFP). To preserve operating margin to alarms and automatic actions on low MFP suction pressure, the setpoints associated with MFP net positive suction head (NPSH) protection, condensate polisher bypass, and feedwater heater bypass will be changed.

- There will be slight increases in the temperatures, pressures, and flows in the extraction steam piping and in the various heater drains. Heater drain pump third-stage impellers will be replaced to increase the capacity of the heater drain pumps and to satisfy uprate heater drain flow requirements, will be installed. The heater drain pump motors will also be replaced.

- The main generator electrical output will increase by approximately 49 megawatts electric (MWe) for Unit 1 and 37 MWe for Unit 2. Each main generator will be re-rated from 1350 to 1410 megavolt amperes (MVA) with an allowable power factor of 0.9. The hydrogen and the exciter air coolers will be replaced and additional cooling will be provided from the turbine plant cooling water (TPCW) system to the exciter air coolers.

- The isophase bus duct coolers will be replaced with 40,000 cfm (cubic feet per minute) to support operations at uprated power level.

- The main transformers are currently operating under administrative voltage limits. The main transformers have been evaluated and found acceptable at SPU conditions with the current administrative limits. The main transformers are scheduled to be replaced due to their age and to enhance their MVAR (megavolt ampere reactive) support capability. CPSES, Unit 2 transformers are scheduled to be replaced in 2009 and CPSES, Unit 1 in 2010, after one cycle of SPU operation.

- A total of nine pipe support modifications (all related to the feedwater system in CPSES, Unit 1) are required due to SPU conditions. The support modifications are minor in nature and involve the installation of one new pipe support on a 3/4-inch drain line and additional items, such as increasing existing weld sizes, adding gussets, reinforcing existing support frame members, etc. There are no piping modifications for CPSES, Unit 2.

- Additional setpoint changes and replacement of process indication scales and rebanding will also be needed to the balance-of-plant (BOP) systems in support of the proposed SPU for both CPSES units.

Operation at SPU conditions affects the reactivity of discharged fuel. Therefore, TS 3.7.17 changes were included in the CPSES, Units 1 and 2 stretch power uprate licensing report (SPULR) (Reference 2), Section 2.8.6.2. As discussed earlier, the amendment request associated with SFP criticality analysis is being processed separately.

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 purpose of the NRC staff's review is to evaluate the licensee's assessment of the impact of the proposed SPU on design-basis analyses. The NRC staff evaluated the licensee's application and supplements.

In areas where the licensee and its contractors used NRC-approved or widely accepted methods in performing analyses related to the proposed SPU, 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 SPU 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

2.1.1 Reactor Vessel Material Surveillance Program

2.1.1.1 Regulatory Evaluation

The reactor vessel (RV) material surveillance program provides a means for 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*,

Part 50 (10 CFR Part 50), Appendix H, provides the staff's requirements for the design and implementation of the RV material surveillance program. The NRC staff's review primarily focused on the effects of the proposed SPU 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 rapidly propagating failure; (2) GDC-31, which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a non-brittle manner and that the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides requirements 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 NUREG-0800, Standard Review Plan (SRP), Chapter 5, Section 5.3.1, Revision 2, "Reactor Vessel Materials," dated March 2007 (ADAMS Accession No. ML063190007).

2.1.1.2 Technical Evaluation

The NRC's regulatory requirements related to the establishment and implementation of a facility's RV materials surveillance program and surveillance capsule withdrawal schedule are given in 10 CFR Part 50, Appendix H. Appendix H to 10 CFR Part 50 invokes by reference the guidance in American Society for Testing and Materials (ASTM) Standard Practice E-185, "Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." ASTM Standard Practice E-185 provides guidelines for designing and implementing the RV materials surveillance programs for operating light-water reactors, including guidelines for determining RV surveillance capsule withdrawal schedules based on the vessel material predicted transition temperature shifts (ΔRTNDT, change in reference temperature nil ductility transition).

The licensee discussed the impact of the 4.5 percent SPU on the RV material surveillance program in Section 2.1.1 of the SPULR (Reference 2). The surveillance capsule withdrawal schedules were provided in Table 2.1.1-2 (CPSES, Unit 1) and Table 2.1.1-3 (CPSES, Unit 2) of the SPULR. The withdrawal schedules were developed in reference to the effective full-power years (EFPY) of plant operation, with a projected value of 36 EFPY at the end of the current license. All ΔRTNDT values were calculated to be less than 100 degrees Fahrenheit (°F). Therefore, at least three surveillance capsules must be withdrawn for the licensed operating period, per the specifications in Table 1 of ASTM Standard Practice E-185. All three of the required surveillance capsules have already been withdrawn at CPSES, Unit 1. The licensee stated that the neutron fluence value obtained from the latest (third) surveillance capsule at CPSES, Unit 1 exceeded the projected neutron fluence value for the current licensed operating period (36 EFPY) under SPU conditions, but was less than twice the value for the current licensed operating period under SPU conditions. Hence, the licensee concluded that the current surveillance capsule withdrawal schedule is still valid for the SPU conditions, and it meets the intent of ASTM Standard Practice E-185. At CPSES, Unit 2, only two surveillance capsules have been removed to date. The schedule for the removal of the third surveillance capsule at CPSES, Unit 2, accounting for SPU conditions, remains compliant with the provisions ASTM Standard Practice E-185.

The staff reviewed the licensee's description of the RV material surveillance program under SPU conditions and finds it acceptable because the neutron fluence from the third surveillance

capsule removed from CPSES, Unit 1 exceeds the projected neutron fluence value for the 36 EFPY licensed operating period under SPU conditions. This capsule fluence is also less than two times (2x) the projected vessel fluence for the licensed operating period under SPU conditions. Therefore, it complies with the specifications in paragraph 7.6.2 of ASTM Standard Practice E-185. Furthermore, consistent with the requirements of paragraph 7.6.2 of ASTM Standard Practice E-185, the licensee stated that the third capsule for CPSES, Unit 2 will be withdrawn when the projected neutron fluence value is less than two times the projected fluence value for the licensed operating period under SPU conditions. Therefore, the staff finds that the licensee's RV material surveillance program for CPSES, Units 1 and 2 complies with the requirements specified in 10 CFR Part 50, Appendix H.

The staff also reviewed the licensee's projected fluence values for the 36 EFPY licensed operating period, accounting for SPU conditions. These fluence values were provided in Table 2.1.1-1 of the SPULR. The staff found that these fluence values were calculated using a methodology described in Westinghouse Topical Report WCAP-14040-NP-A, Revision 4, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and Reactor Coolant System (RCS) Heatup and Cooldown Limit Curves," May 2004. This methodology has been reviewed and approved by the NRC staff, and it adheres to the guidance of Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for determining Pressure Vessel Neutron Fluence," March 2001. Therefore, the staff found that the SPU fluence projections were acceptable.

2.1.1.3 Conclusion

The NRC staff concludes that the licensee has adequately addressed the impact of the proposed SPU on the RV material surveillance program at CPSES, Units 1 and 2. The NRC staff further concludes that the existing RV surveillance capsule withdrawal schedule is appropriate to ensure that the material surveillance program 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 GDC-14 and GDC-31, following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the RV material surveillance program.

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

2.1.2.1 Regulatory Evaluation

Appendix G to 10 CFR Part 50 provides fracture toughness requirements for ferritic materials (low alloy steel or carbon steel) in the RCPB, including upper-shelf energy (USE) requirements for ensuring adequate safety margins against ductile tearing, as well as requirements for calculating pressure-temperature (P-T) limits for the plant. Appendix G to 10 CFR Part 50, requires that RCPB materials satisfy the criteria in Appendix G of Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) in order to ensure the structural integrity of the RCPB during any condition of normal operation, including anticipated operational occurrences (AOOs) and hydrostatic tests.

The NRC's acceptance criteria 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 a safety margin sufficient to assure that, under specified conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized; (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.

2.1.2.2 Technical Evaluation

2.1.2.2.1 Upper-Shelf Energy Value Calculations

10 CFR Part 50, Appendix G provides the staff's criteria for maintaining acceptable levels of USE for the RV beltline materials of operating reactors throughout the licensed operational lives of the facilities. The rule requires RV beltline materials to have a minimum USE value of 75 foot-pounds (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 analysis that lower values of USE would provide acceptable margins of safety against fracture equivalent to those required by Appendix G of the ASME Code, Section XI. The rule also mandates that the methods used to calculate USE values must account for the effects of neutron radiation 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 NRC staff's recommended guidelines for calculating the effects of neutron radiation on the USE values for the RV beltline materials are specified in RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials."

The licensee discussed the impact of the 4.5 percent SPU on the USE values for the RV beltline materials in Section 2.1.2 of the SPULR. The applicant demonstrated that all RV beltline materials at CPSES, Units 1 and 2 have a USE greater than 50 ft-lb through the end of license (EOL), as required by Appendix G to 10 CFR Part 50. Table 2.1.2-3 of the of the SPULR provides the predicted USE values for the CPSES, Units 1 and 2 beltline materials, based on neutron fluence values at 36 EFPY. The projected 36 EFPY peak fluence values at the one-quarter of the vessel wall thickness (1/4T) location are 1.33×10^{19} n/cm^2 (E > 1.0 MeV) for CPSES, Unit 1 and 1.34×10^{19} n/cm^2 (E > 1.0 MeV) for CPSES, Unit 2, accounting for SPU conditions. For CPSES, Unit 1, the licensee determined that Lower Shell Plate R-1108-1 is the RV beltline material with the most limiting USE value. The licensee determined that the USE value for this material at EOL, accounting for SPU conditions, is 67.6 ft-lb, based on Regulatory Position 1.2 of RG 1.99, Revision 2. Regulatory Position 1.2 of RG 1.99, Revision 2 utilizes Figure 2 of the RG to determine a percentage drop in the USE based on projected fluence and copper content when no surveillance data is available. For CPSES, Unit 2, the licensee determined that Intermediate Shell Plate R-3807-2 is the RV beltline material with the most limiting USE value. The licensee determined that the USE value for this material at EOL, accounting for SPU conditions, is 80.3 ft-lb based on Regulatory Position 1.2 of RG 1.99, Revision 2. The licensee stated that Regulatory Position 1.2 was used for calculating these EOL USE values because no surveillance data was available for these materials.

The staff performed independent calculations of the EOL USE values for the CPSES, Units 1 and 2 RV beltline materials using the limiting 36 EFPY neutron fluence value at the 1/4T location in the RV shell, accounting for SPU conditions. For CPSES, Unit 1, the staff confirmed

that Lower Shell Plate R-1108-1 is the RV beltline material with the most limiting USE value. The staff calculated a 68.9 ft-lb USE value using Regulatory Position 1.2 for this material at EOL. This was in general agreement with the licensee's USE calculation for this material. For CPSES, Unit 2, the staff confirmed that Lower Shell Plate R-3807-2 is the RV beltline material with the most limiting USE value. The staff calculated an 83.3 ft-lb USE value using Regulatory Position 1.2 for this material at EOL. This was in general agreement with the licensee's USE calculation for this material. The staff also agreed that the licensee had correctly applied Regulatory Position 1.2 of RG 1.99, Revision 2 for determining the USE values for these materials. Based on its independent USE calculations, the staff determined that the beltline materials in the CPSES, Units 1 and 2 RVs will have acceptable USE values under the SPU conditions for the remainder of the current licensed operating period.

2.1.2.2.2 P-T Limit Calculations

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 using the calculation methods specified in the ASME Code, Section XI, Appendix G. The rule also requires that the P-T limit calculations account for the effects of neutron radiation on the material properties of the RV beltline materials and that P-T limit calculations incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its 10 CFR Part 50, Appendix H RV materials surveillance program. The NRC staff's recommended guidelines for calculating the effects of neutron radiation on the adjusted reference temperature (ART) values used for P-T limit calculations are specified in RG 1.99, Revision 2.

At 36 EFPY, the maximum projected fluence at the inside surface of the RV, accounting for SPU conditions, is 2.23×10^{19} n/cm^2 (E > 1.0 MeV) for CPSES, Unit 1 and 2.25×10^{19} n/cm^2 (E > 1.0 MeV) for CPSES, Unit 2. The licensee had previously developed P-T limit curves for CPSES, Units 1 and 2 applicable to 36 EFPY based on a maximum projected fluence at the inside surface of the RV of 2.45×10^{19} n/cm^2 (E > 1.0 MeV) for CPSES, Unit 1. This maximum projected 36 EFPY fluence for CPSES, Unit 1 was used for calculating the P-T limits for both CPSES units. These P-T limit curves and supporting calculations (Reference 17) utilized the maximum projected 36 EFPY fluence for CPSES, Unit 1, based on the dosimetry from surveillance capsules U and Y. The current 36 EFPY fluence projections for the SPU now include the dosimetry from surveillance capsules U, Y, and X for CPSES, Unit 1. The licensee stated that the neutron fluence values for 36 EFPY under SPU conditions included the analysis of the latest surveillance capsule (X) for CPSES, Unit 1. Therefore, the SPU fluence values for CPSES, Units 1 and 2 are less than the value (2.45×10^{19} n/cm^2 (E > 1.0 MeV)) that was used for the current P-T limits, which was derived from the analysis of capsules U and Y for CPSES, Unit 1. The initial RTNDT and chemistry factor (CF) values for the CPSES, Units 1 and 2 RV beltline materials are unchanged as a result of the SPU. Therefore, the ART values, when calculated using the lower fluence values, would likewise be lower in magnitude than the ART values used for the current P-T limit calculations. Therefore, the P-T limit curves, currently represented in the CPSES, Units 1 and 2 P-T Limits Report (PTLR), remain bounding for SPU conditions.

2.1.2.3 Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the USE values for the RV beltline materials and P-T limits. The staff concludes that the licensee has adequately addressed the impact of the SPU on the CPSES, Units 1 and 2 USE values and P-T limits. Specifically, the staff finds that the CPSES, Unit 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 license for the facility (36 EFPY) and that the licensee has demonstrated the validity of the proposed P-T limits for operation under the proposed SPU conditions. Based on this assessment, the NRC staff concludes that CPSES, Units 1 and 2 will continue to meet the requirements of 10 CFR Part 50, Appendix G, 10 CFR 50.60, GDC-14, and GDC-31 following implementation of the proposed SPU.

2.1.3 Pressurized Thermal Shock

2.1.3.1 Regulatory Evaluation

The pressurized thermal shock (PTS) evaluation provides a means for assessing the susceptibility of the RV beltline materials to PTS events in order to ensure that these materials have adequate fracture toughness to support reactor operation. The staff's requirements, methods of evaluation, and safety criteria for PTS assessments are given in 10 CFR 50.61. The NRC staff's review covered the licensee's PTS methodology and PTS reference temperature (RTPTS) calculations at the expiration of the operating license, taking into consideration the effects of neutron embrittlement. 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 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 non-brittle 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.

2.1.3.2 Technical Evaluation

The staff has established requirements in 10 CFR 50.61 to protect PWR vessels against the consequences of PTS events. The rule requires licensees operating PWRs to calculate EOL RTPTS values (as defined in 10 CFR 50.61) for each base metal and weld material in the RV constructed from carbon or low-alloy steel materials. The rule also requires that RTPTS values remain below the PTS screening criteria throughout the serviceable life of the facilities. The rule sets a maximum limit of 270 °F for RTPTS values that are calculated for base metals (i.e., forging and plate materials) and axial weld materials and a maximum limit of 300 °F for RTPTS values that are calculated for circumferential weld materials.

Section 50.61 of 10 CFR provides a required methodology for calculating these RTPTS values, which are the same as the calculation methods in RG 1.99, Revision 2. For materials in the beltline region of the RV, the rule requires that the calculations account for the effects of neutron radiation on the RTPTS 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.

The licensee discussed the impact of the SPU on the CPSES, Units 1 and 2 PTS assessment in Section 2.1.3 of the SPULR. The licensee stated that the PTS assessment for the CPSES, Unit 1 RV, accounting for SPU conditions, is limited by Lower Shell Plate R-1108-2 and that this material has a limiting RTPTS value of 99 °F at EOL (36 EFPY). For CPSES, Unit 2, the licensee determined that the limiting material for the PTS evaluation, accounting for SPU conditions, is Intermediate Shell Plate R-3807-2 and that this material has a limiting RTPTS value of 89 °F at EOL (36 EFPY). The staff independently confirmed the validity of these RTPTS calculations. The licensee's EOL RTPTS values for the limiting materials are far less than the 270 °F screening limit specified in 10 CFR 50.61.

The licensee also reported RTPTS values based on Regulatory Position 2.1 of RG 1.99, Revision 2, because credible surveillance capsule test data was available for establishing RTPTS values for the limiting materials above. However, these values were less conservative (i.e., lower) than those obtained using Regulatory Position 1.1 of RG 1.99, and the licensee stated that the RTPTS values based on Regulatory Position 1.1 are designated as the actual RTPTS values for these materials. Therefore, the RTPTS values calculated by the licensee and the staff are consistent and are well within the 270 °F PTS screening criterion established for base metals in 10 CFR 50.61. The staff therefore concludes that the beltline materials in the CPSES, Unit 1 and 2 RVs will have acceptable safety margins against the consequences of PTS events under the SPU conditions, as required by 10 CFR 50.61.

2.1.3.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the PTS evaluation for CPSES, Units 1 and 2 and concludes that the licensee has adequately addressed the impact of the proposed SPU on the PTS evaluation. The NRC staff further concludes that the licensee has demonstrated that the plant will continue to meet the requirements of GDC-14 and GDC-31, and 10 CFR 50.61 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to PTS.

2.1.4 Reactor Internal and Core Support Materials

2.1.4.1 Regulatory Evaluation

The reactor internal (RI) components 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 RCS). The NRC staff reviewed the materials' specifications, mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation for these components. The NRC's acceptance criteria for RI and core support materials are based on GDC-1 and 10 CFR 50.55a. Specific review criteria are contained in SRP Section 4.5.2.

2.1.4.2 Technical Evaluation

The licensee discussed the impact of the SPU on the structural integrity of the CPSES, Units 1 and 2 RI components in Section 2.1.4 of the SPULR. In this section, the licensee assessed the RI components and found them acceptable for continued operation through the end of the current licensed operating period (36 EFPY) under SPU conditions.

The licensee analyzed the impact of the SPU on the performance of the RI components, taking into consideration the following aging mechanisms:

- Integrity of Fuel Cladding
- Intergranular Stress-Corrosion Cracking (IGSCC), Transgranular Stress-Corrosion Cracking (TGSCC), and Primary Water Stress-Corrosion Cracking (PWSCC)
- Irradiation Embrittlement and Irradiation-Assisted Stress-Corrosion Cracking (IASCC)
- Void Swelling
- Thermal Aging

2.1.4.2.1 Integrity of Fuel Cladding

The licensee addressed the effects of the proposed SPU on the potential degradation of fuel cladding due to corrosion. Proper control of RCS water chemistry in accordance with specifications in the Electric Power Research Institute (EPRI) report EPRI-TR1002884, “Pressurized Water Reactor Primary Water Chemistry Guidelines,” is essential in adequately managing fuel cladding corrosion effects. The licensee further stated that the industry experience and available laboratory results suggest that when RCS water chemistry complies with these guidelines, no discernable degradation due to fuel cladding corrosion occurs. The staff reviewed the licensee’s evaluation and finds it acceptable because the licensee continues to comply with the EPRI guidelines that were established for controlling RCS water chemistry through the end of the current licensed operating period (36 EFPY).

2.1.4.2.2 IGSCC, TGSCC, and PWSCC

The licensee addressed the effect of the proposed SPU on the potential degradation of RI components by stress-corrosion cracking (SCC), specifically IGSCC, TGSCC, and PWSCC. Historically, SCC in susceptible austenitic stainless steel (SS) and nickel-based alloy RI components occurs under the following conditions:

- Presence of oxygen and/or aggressive ions (i.e., chlorides and sulphates) in RCS environments,
- Temperature greater than 200 °F and,
- Presence of stress.

All three of these variables must be simultaneously present in order for RI components to undergo any form of SCC. Susceptibility to IGSCC generally requires (1) RI component materials that have been “sensitized” as a result of prior welding and heat treatment processes, and (2) the presence of oxygen in RCS environments. Susceptibility to TGSCC generally requires the presence of oxygen as well as aggressive ions in the RCS environment. The licensee stated that, by controlling the RCS water chemistry per the EPRI-TR1002884 report, TGSCC and IGSCC will be adequately mitigated in RI components. The licensee further stated that the minimal increase in temperature resulting from the SPU will not adversely affect the TGSCC or IGSCC behavior in austenitic SS RI components. The staff agreed with the licensee’s determination that the relatively small temperature changes associated with the implementation of the SPU will not adversely affect the susceptibility of the RI components to TGSCC or IGSCC, and any increase in RI component stress resulting from higher flow rates associated with SPU conditions will be extremely small and have a negligible impact on overall susceptibility to SCC. The staff also agreed that controlling the RCS water chemistry in accordance with the EPRI-TR1002884 report will adequately mitigate IGSCC and TGSCC in RI components under SPU conditions. Therefore, the staff found that the licensee’s evaluation of TGSCC and IGSCC in RI components under SPU conditions is acceptable.

PWSCC has historically been observed in nickel-based Alloy 600 and X-750 materials in primary-water environments in PWRs. RI components fabricated from these materials include the rod cluster control assembly (RCCA) guide tube support pins (Alloy X-750), clevis insert bolts (Alloy X-750), and clevis inserts (Alloy 600). For all of these nickel-based alloy components, the licensee stated that the minimal temperature changes due to the SPU will not adversely affect PWSCC behavior in any of these components. The staff agreed with the licensee’s determination that the relatively small temperature changes associated with the implementation of the SPU will not adversely affect the susceptibility of the RI components to PWSCC, and any increase in RI component stress resulting from higher flow rates associated with SPU conditions will be extremely small and have a negligible impact on overall susceptibility to SCC. The staff also agreed that controlling the RCS water chemistry in accordance with the EPRI-TR1002884 report will adequately mitigate PWSCC in RI components under SPU conditions. Therefore, the staff found that the licensee’s evaluation of PWSCC in RI components under SPU conditions is acceptable.

2.1.4.2.3 Radiation Embrittlement and IASCC

IASCC behavior in PWR RI components is thought to be caused by the synergistic effects of radiation embrittlement, coincident with a high stress state, in PWR RCS environments. IASCC has the potential to occur when austenitic SS and nickel-based alloy RI components are exposed to neutron fluence values greater than 1×10^{21} n/cm^2 ($E > 0.1$ MeV). PWR RI components such as the lower core barrel, baffle/former assembly, baffle/former bolts, lower core plate and fuel pins, lower support forging, and clevis bolts are potentially prone to radiation embrittlement and IASCC.

The licensee provided projected maximum fast neutron exposure levels (36 EFPY) for the RI components in Table 2.1.4-1 (CPSES, Unit 1) and Table 2.1.4-3 (CPSES, Unit 2) of the SPULR. At CPSES, the following RI components are exposed to the highest fluence levels and are therefore most susceptible to IASCC:

- Lower Core Plate and Fuel Alignment Pins
- Lower Support Columns
- Core Barrel and Core Barrel Flange in the Active Core Region
- Thermal Shield
- Bolting-Lower Support Column, Baffle-Former, and Barrel-Former

The EOL fluence levels for the components listed above are all on the order of 1 X 10^{23} n/cm^2 (E > 0.1 MeV); these components are, therefore, considered susceptible to IASCC during the current license term. Accordingly, the licensee has committed to follow the EPRI Materials Reliability Program (MRP) initiatives concerning age-related degradation in RI components. The staff determined that the licensee's implementation of the results of the EPRI MRP initiative will identify aging effects due to radiation embrittlement and IASCC in a timely manner so that proper steps can be taken by the licensee to ensure the structural integrity and functionality of any given RI component. Therefore, the staff found that the licensee's evaluation of IASCC in RI components under SPU conditions is acceptable.

2.1.4.2.4 Void Swelling

Void swelling is an age-related degradation mechanism characterized by a general increase in the volume of the component when exposed to high levels of neutron radiation. Industry experience thus far suggests that, in general, significant void swelling can occur in RI components that are exposed to neutron radiation during normal plant operating conditions. PWR baffle bolts have been known to undergo a minor amount of void swelling, although such swelling levels are not significant enough to affect their intended function during the plant's operating life. The licensee has committed to follow the recommendations that are currently being developed by the EPRI MRP initiative regarding void swelling. The EPRI MRP initiative will address inspection methods and frequency of inspections for RI components that are deemed susceptible to void swelling. These inspections will adequately identify void swelling in a timely manner and will facilitate implementation of proper corrective actions by the licensee to ensure structural integrity and/or functionality of the component. Therefore, the staff found that the licensee's evaluation of void swelling in RI components under SPU conditions is acceptable.

2.1.4.2.5 Thermal Aging

Cast austenitic stainless steels (CASS), when exposed to temperatures above 482 °F, may be susceptible to thermal aging embrittlement. The degree of embrittlement depends on the chemical composition and initial microstructure of the material, the aging temperature, and time at temperature. The licensee indicated that the CPSES, Unit 1 RI components contain some CASS materials. The CASS materials in the CPSES, Unit 1 RI components have low-

molybdenum content (0.5 weight percent maximum), which is favorable from the standpoint of thermal aging behavior. The licensee also indicated that the RCS service temperature for these CASS-containing components will not result in embrittlement significant enough to impact structural integrity during the current operating life of the plant. In a conference call conducted on March 26, 2008, the staff requested that the licensee provide some data pertaining to the initial microstructural condition of the CASS materials in the CPSES, Unit 1 RI components. The staff specifically requested that the licensee provide written information pertaining to (1) the delta ferrite content of these CASS materials and (2) the casting method used in the manufacture of these CASS materials. High delta ferrite content in CASS materials (greater than 20 percent delta ferrite for low-molybdenum steels) is known to result in susceptibility to thermal aging for CASS components manufactured by static casting. Conversely, it has been established that low-molybdenum static-cast CASS materials with a delta ferrite content of less that 20 percent are not susceptible to thermal aging in primary-water environments. It has also been established that all centrifugal-cast, low-molybdenum CASS materials are not susceptible to thermal aging, regardless of the initial delta ferrite content. The licensee provided this information by letter dated May 14, 2008. Based on this information, the staff determined that thermal aging is not a significant degradation concern for the CPSES, Unit 1 RI components containing CASS materials because the delta ferrite content for these static-cast components is estimated to be less than 6 percent. The licensee stated in the SPU licensing report that the CPSES, Unit 2 RI components do not contain any CASS materials. Furthermore, the minimal temperature changes due to the SPU will not adversely affect thermal aging behavior in any of the CPSES, Units 1 and 2 RI components. Therefore, the staff found that the licensee's evaluation of thermal aging in RI components under SPU conditions is acceptable.

2.1.4.3 Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the susceptibility of RI 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 RI and core support materials. The NRC staff further concludes that the licensee has demonstrated that the RI components will continue to meet the requirements of GDC-1 and 10 CFR 50.55a following implementation of the proposed SPU. Therefore, the staff concludes that proposed license amendment is acceptable with respect to the structural integrity assessments of the RV and RI components.

2.1.5 Reactor Coolant Pressure Boundary Materials

2.1.5.1 Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff's review of RCPB materials covered their 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 non-brittle manner and the probability of a rapidly propagating fracture is minimized; and (5) 10 CFR 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 Generic Letter (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.

2.1.5.2 Technical Evaluation

This section of the report summarizes the evaluations and results of the potential materials degradation issues arising from the effect of the CPSES SPU on the performance of RCPB component materials.

The primary concern from the proposed power uprate is the potential effect of changes in the RCS chemistry (impurities) and pH (potential of Hydrogen) conditions, and the power uprate service temperatures on the integrity of RCS component materials during service. These concerns include general corrosion (wastage) and SCC of system materials, fuel corrosion, and PWSCC of nickel-based alloys.

A review of the SPU design parameters indicates that the following changes in the RCS chemistry and service temperature conditions occur during operations after the SPU implementation:

- The reactor coolant lithium/boron chemistry program is coordinated such that a target pH range between 7.19 and 7.40 is maintained with an initial target lithium level of 5.71 parts per million (ppm). The lithium level is then decreased gradually during the fuel cycle as the boron diminishes, thus maintaining a target pH value of 7.40 through the end of the fuel cycle. This is the current chemistry program employed at CPSES.

- For CPSES, Unit 1, a maximum increase in the peak steady-state service temperature of 1.2 °F at the RV hot-leg location and a decrease in service temperature of 1.2 °F at the RV cold-leg and bottom-mounted instrumentation (BMI) penetration locations will occur due to the SPU. This is summarized in Table 2.1.5-1 of SPULR.

- For CPSES, Unit 2, a maximum increase in the peak steady-state service temperature of 1.8 °F at the RV hot-leg location and a decrease in service temperature of 1.8 °F at the RV cold-leg and BMI penetration locations will occur due to the SPU. This is summarized in Table 2.1.5-2 of SPULR.

The licensee evaluated the effect of the proposed service conditions on the performance of RCS materials as follows.

2.1.5.2.1 Austenitic Stainless Steels

The two degradation mechanisms that are operative in the pressure boundary austenitic SS (base and weld) materials in the RCPB are IGSCC and TGSCC. Susceptible materials, sensitized microstructure, and the presence of oxygen are required for the occurrence of IGSCC, while the introduction of halogens such as chlorides and the presence of oxygen are prerequisites for the occurrence of TGSCC.

The SPU reactor coolant lithium/boron program is coordinated such that an elevated pH value is maintained during the fuel cycle with an initial lithium level target value of 5.71 ppm. The chemistry changes resulting from the SPU do not involve introduction of any of these contributors so that no effect on material degradation is expected in the SS components as a result of the SPU. There is a negligible increase in material degradation due to the increased temperature change.

The licensee stated that the proposed lithium, boron, and pH management program meets the EPRI chemistry guidelines. Since these guidelines are specifically designed to prevent fuel cladding corrosion effects such as fuel deposit build-up and Alloy 600 PWSCC, there will be no adverse effect on fuel cladding corrosion as a result of the proposed power uprate. Experience with operating plants as well as with the guidelines provided by EPRI suggest that increasing initial lithium concentrations of up to 3.5 ppm with controlled boron concentrations to maintain pH values between 6.9 to 7.4 has not produced any undesirable material integrity issues. CPSES units plan to maintain lithium levels at 3.5 ppm or less and thus no adverse effects from this aspect on the SPU is expected to occur.

2.1.5.2.2 Alloy 600/82/182 Components

The licensee has identified Alloy 600 material and/or Alloy 82/182 welds in the following RCS locations:

- RV inlet nozzle welds
- RV outlet nozzle welds
- Pressurizer surge, spray, safety, and relief nozzle welds
- Alloy 600 BMI nozzles and J-groove welds
- RV core guide lug shell cladding
- Alloy 600 RI clevis inserts

- RV upper head control rod drive mechanisms and head vent penetrations (CPSES, Unit 2 only)

- Steam generator U-tubes, tubesheet cladding, partition plate, channel head drain, tube-to-tubesheet welds (CPSES, Unit 2 only)

For a given stress within a material, the most significant factor that influences the PWSCC of Alloy 600/82/182 components is the service temperature. The two most significant Alloy 600/82/182 components that are bounding to the PWSCC susceptibility are the RV hot-leg nozzle welds and the BMI nozzles. Tables 2.1.5-1 and 2.1.5-2 of SPULR show the operating temperature for the BMI nozzles and the hot-leg nozzle weld. At full power, the maximum range of hot-leg temperature is 620.4 °F for both CPSES units. This represents a hot-leg nozzle weld temperature increase of 1.2 °F for CPSES, Unit 1 and an increase of 1.8 °F for CPSES, Unit 2. The licensee calculated the maximum change in the PWSCC susceptibility. Based on the change in operating temperature, an increase in the PWSCC susceptibility of 17 percent was estimated for the hot-leg nozzle weld as a result of the SPU for CPSES, Unit 1. For CPSES, Unit 2, an increase in the PWSCC susceptibility of 25 percent was estimated for the hot-leg nozzle weld as a result of the SPU. The licensee states the increase in PWSCC susceptibility is not considered significant since the absolute susceptibility of this location is estimated to be very low. Even if the staff does not agree with the licensee's basis for not considering the change in susceptibility as significant, the current inspection requirements for Alloy 600/182/82 components are adequate to provide reasonable assurance of structural integrity of these components for any range of temperatures.

The SPU causes a net decrease in the core inlet temperature that corresponds to a decrease in the PWSCC susceptibility for the RV head penetrations (RVHPs) and BMI penetrations. Furthermore, since the BMIs are fabricated from PWSCC-susceptible Alloy 600/82/182 material, the CPSES, Unit 1 BMIs are subject to NRC BL 2003-02 requiring certain inspections for the safe management of the BMI PWSCC issue. In support of this, the licensee performs visual inspection of BMIs every refueling outage.

The CPSES, Unit 1 RV closure head with Alloy 600/82/182 penetrations was replaced in early 2007 with a new head with Alloy 690/52/152 control rod drive mechanism (CRDM) penetrations. Laboratory and field experience to date suggests that Alloy 690 and associated Alloy 52/152 welds are resistant to PWSCC. On this basis, the proposed SPU is not expected to have an impact on the PWSCC degradation of the Alloy 690/52/152 RVHPs.

The industry experience over the past decade showed that the PWSCC susceptibility of the Alloy 600/82/182 outermost circle RVHPs is considered bounding to other Alloy 600 primary component locations due to the presence of high residual stresses and service temperatures at those penetration locations. Since CPSES, Unit 2 is a cold-head plant, the best-estimate mean fluid maximum service temperature at the RVHPs is considered to be the core inlet temperature for the purpose of the current evaluation. This value was established from the data in Table 2.1.5-2 of SPULR to be 558 °F, a 1.8 °F decrease at SPU conditions for CPSES, Unit 2.

The SPU causes a net decrease in the core inlet temperature, which corresponds to a decrease in the PWSCC susceptibility for the RVHPs and BMI penetrations. Furthermore, since the BMIs are fabricated from PWSCC-susceptible Alloy 600/82/182 material, the CPSES, Unit 2 BMIs are

subject to NRC BL 2003-02 request for certain inspections for the safe management of the BMI PWSCC issue. In support of this, the licensee performs visual inspections of CPSES, Unit 2 BMIs every refueling outage.

The licensee concluded that no new material degradation issues of carbon steel boric acid corrosion are expected due to the SPU water chemistry; the risk of PWSCC of the Alloy 600/82/182 CPSES, Units 1 and 2 BMI penetrations and the CPSES, Unit 2 RVHPs does not increase; the SPU will not affect any changes to the Aging Management Program (AMP); and no material degradation is expected in the SS components as a result of the SPU.

2.1.5.2.3 Thermal Aging

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

An increase in the hot-leg temperature of 1.2 °F for CPSES, Unit 1 and a 1.8 °F increase in the hot-leg temperature for CPSES, Unit 2 was assessed due to the SPU. The effect of this change in the service temperature on the thermal aging is considered.

Topical report WCAP-14575, “Licensing Renewal Evaluation: Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components,” December 2000, indicates that thermal aging causes a reduction in fracture toughness of the CASS component material and hence a reduction in the critical flaw size that could lead to component failure. The impacted RCPB CASS components include primary piping and its welds, valve bodies, and pump casings. WCAP-14575 proposed programs to manage the effects of thermal aging of CASS components during the period of extended operation. Any potential effect on thermal aging due to the SPU would be contained within the proposed programs of WCAP-14575.

The licensee also concluded that no new materials degradation issues will result from the proposed SPU at CPSES, and that the new SPU environmental conditions will not introduce any significant aging effects on their components during the current licensing basis, nor will the SPU change the manner in which component aging is managed by the AMP.

2.1.5.3 Conclusion

The staff reviewed the information provided by the licensee regarding the effects of the SPU on the integrity of RCS materials and found it acceptable. The staff finds that while the increase in temperature during SPU conditions at CPSES, Units 1 and 2 has an effect on RCS component materials, the licensee’s activities to maintain chemistry control and an effective inspection program provide an acceptable level of quality and safety. The staff agrees with the licensee’s conclusion that the above-listed materials will not be adversely affected in a significant manner due to the SPU.

Based upon the results of its review, the staff concludes that the licensee has adequately evaluated the effects of SPU on the integrity of RCS materials. The NRC staff further concludes that the licensee has demonstrated that the RCS materials will continue to be acceptable

following implementation of the proposed SPU and will continue to meet the requirements of GDC-1, GDC-4, GDC-14, and GDC-31; 10 CFR Part 50, Appendix G; and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed SPU acceptable with respect to RCS materials.

2.1.6 Leak Before Break

2.1.6.1 Regulatory Evaluation

Leak before break (LBB) analyses provide a means for eliminating from the design basis the dynamic effects of postulated pipe 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 for 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 over-pressurizations, fires, 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.

2.1.6.2 Technical Evaluation

The licensee stated that the current structural design basis for CPSES, Units 1 and 2 includes the application of the LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping, pressurizer surge line, residual heat removal (RHR) piping, and the accumulator injection lines. Section 2.1.6.2 of the SPULR describes the analyses and evaluations performed to demonstrate that the elimination of these breaks continues to be justified at the operating conditions associated with the CPSES, Units 1 and 2 SPU.

According to the licensee, LBB analyses were performed for the CPSES, Unit 1 RCS primary loop, pressurizer surge line, RHR piping, accumulator injection nozzles, and the accumulator injection lines. The analyses for CPSES, Unit 1 are documented in WCAP-10527, dated April 1984; WCAP-12248 Supplement 3, dated June 1990; CPSES, Unit 1, WHIPJET program report, dated April 1988 and May 1989; WCAP-12258 Supplement 2, dated August 1989; and WCAP-12267, dated May 1989. LBB analyses were performed for the CPSES, Unit 2 RCS primary loop, pressurizer surge line, RHR lines, and the accumulator lines (including nozzles). The analyses for CPSES, Unit 2 are documented in WCAP-10527, dated April 1984; WCAP-13100, dated December 1991; WCAP-13165, dated December 1991; and WCAP-13167, dated January 1992 to support the CPSES, Units 1 and 2 SPU, the previous LBB analyses formed the basis for the SPU LBB analysis. The primary loop piping, pressurizer surge line, RHR lines, and the accumulator lines, deadweight, normal thermal expansion and stratification (for RHR and pressurizer surge line), and safe-shutdown earthquake (SSE) and pressure loads due to the SPU conditions were employed. The SPU normal operating temperature range and pressure were used in the evaluation. The evaluation results demonstrated that all the LBB-recommended margins for the primary loop piping, pressurizer surge line, RHR lines, and the accumulator lines continue to be satisfied for the SPU conditions.

The LBB acceptance criteria and the recommended margins stated in SRP 3.6.3, Revision 1, are as follows:

- Margin of 10 on leak rate
- Margin of 2 on flaw size
- Margin of 1 on loads (using normal plus faulted load combinations by the absolute summation method) or margin on loads of 1.4 (normal plus SSE loads)

The evaluation results demonstrated that all the LBB-recommended margins for the primary loop piping, pressurizer surge line, RHR piping, accumulator injection nozzles, and the accumulator injection lines are satisfied for the SPU conditions. The evaluation results demonstrated the following:

- Leak rate – A margin of 10.0 exists between the calculated leak rate from the leakage flaw and the leak detection capability of 1 gallon per minute (gpm).
- Flaw size – A margin of 2.0 or more exists between the critical flaw size and the leakage flaw size.
- Loads – A margin of 1.0 on loads using normal plus faulted load combinations by the absolute summation method or a margin on loads of 1.4 exists.

The evaluation results demonstrated that the LBB conclusions provided in current LBB analyses for CPSES, Units 1 and 2 remain unchanged for the SPU conditions. The licensee determined that the LBB acceptance criteria are satisfied for the CPSES, Units 1 and 2 SPU the primary loop piping, pressurizer surge line, RHR piping, accumulator injection nozzles, and the accumulator injection lines under SPU conditions. All the recommended margins are satisfied and the conclusions shown in the current LBB analyses remain valid. Therefore, the licensee concluded that the dynamic effects of RCS primary loop piping, pressurizer surge line, RHR piping, accumulator injection nozzles, and the accumulator injection line breaks need not be considered in the structural design basis of CPSES, Units 1 and 2 at SPU conditions.

2.1.6.3 Conclusion

The staff reviewed the information submitted by the licensee concerning the potential impact of the proposed CPSES, Units 1 and 2 SPU on the acceptability of the LBB status of the RCS primary loop piping, pressurizer surge line, RHR piping, accumulator injection nozzles, and the accumulator injection lines. The primary system pressure, primary system temperature, material properties, and design-basis SSE loadings are the parameters that could have a significant impact on the facility's LBB evaluation. The licensee has demonstrated that the LBB acceptance criteria and the recommended margins based on SRP Section 3.6.3, Revision 1, would be maintained under SPU conditions at CPSES, Units 1 and 2. Therefore, the staff concludes that the changes to the LBB evaluation for this piping resulting from the proposed SPU will not alter the staff's previous conclusions stated in the NRC-approved Fracture Proof Design Corporation Report. The staff concludes that, per the provisions of 10 CFR Part 50,

Appendix A, GDC-4, the dynamic effects from postulated breaks of the CPSES, Units 1 and 2 RCS primary loop piping, pressurizer surge line, RHR piping, accumulator injection nozzles, and the accumulator injection lines may continue to be excluded from the licensing basis of the facility for post-SPU conditions. The NRC staff further concludes that the licensee has demonstrated that the LBB analyses will continue to be valid following implementation of the proposed SPU and that lines for which the licensee credits LBB will continue to meet the requirements of GDC-4. Therefore, the NRC staff finds the proposed SPU acceptable with respect to LBB.

2.1.7 Protective Coating Systems (Paints) - Organic Materials

2.1.7.1 Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of structures 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 accident (DBLOCA) conditions, considering radiation and chemical effects. Protective coatings systems used inside containment were initially qualified in accordance with American National Standards Institute (ANSI) N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities" (Reference 43). However, due to concerns during the final construction stages, NUREG-0797 Supplement 9, Safety Evaluation Report related to the operation of CPSES, Units 1 and 2, was approved in March 1985 which allowed the licensee to declassify the protective coatings in containment and not require the use of qualified coating systems.

2.1.7.2 Technical Evaluation

Protective coatings (paints) inside containment are used to protect equipment and structures from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance activities. The durability and qualification of the coating systems performed in accordance with ANSI N101.2 are based, in part, on the containment accident temperature and pressure profiles following a DBLOCA. These parameters are a function of the energy released from RCS during a DBLOCA. The licensee performed a reanalysis using the Generation of Thermal Hydraulic Information for Containments (GOTHIC) code and concluded that the containment temperature and pressure do not increase at the SPU conditions. Based on the conclusion that the design-basis accident (DBA) temperature and pressure profiles are not negatively affected by the SPU, it is concluded that there will be no impact on the performance of the coatings.

2.1.7.3 Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on protective coating systems and concludes that the licensee has appropriately addressed the impact of changes in conditions following a DBLOCA and their effects on the protective coatings. The NRC staff further concludes that the licensee has demonstrated that the protective coatings will continue to be acceptable following implementation of the proposed SPU

and will continue to meet the requirements of its licensing basis. Therefore, the NRC staff finds the proposed SPU acceptable with respect to protective coatings systems.

The licensee is in the process of updating the coating qualifications as part of the resolution of Generic Safety Issue (GSI) 191, "Assessment of Debris Accumulation on PWR Sump Performance." As stated in a letter TXX-05162 submitted to the NRC on September 1, 2005, the licensee is currently reevaluating declassified coatings inside containment and program changes are being made to restore a safety-related coatings program and to restore qualification for containment coatings. The licensee has made a commitment (Commitment No. 27448) that the SPU conditions will be considered as part of the restoration of the containment coating qualifications.

2.1.8 Flow-Accelerated Corrosion (FAC) Program

2.1.8.1 Regulatory Evaluation

Flow-accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to flowing single- or two-phase water. Components made from SS are immune to FAC, and FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on velocity of flow, fluid temperature, steam quality, oxygen content, and pH. During plant operation, control of these parameters is limited and the optimum conditions for minimizing FAC effects, in most cases, cannot be achieved. Loss of material by FAC will, therefore, occur. The NRC staff has reviewed the effects of the proposed SPU on FAC and the adequacy of the licensee's FAC program to predict the rate of loss so that repair or replacement of degraded components could be made before they reach critical thickness. The licensee's FAC program is based on NUREG-1344, GL 89-08, and the guidelines in EPRI Report NSAC-202L-R2. It consists of predicting loss of material using the CHECWORKS computer code, and 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.

2.1.8.2 Technical Evaluation

FAC is a corrosion mechanism occurring in carbon steel components exposed to flowing single- or two-phase water. FAC results in wall thinning and possible failure of high-energy carbon steel pipes in the power conversion system. The rate of wear due to FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss by FAC depend on fluid velocity, temperature, steam quality, oxygen content, and pH. During plant operation, control of these parameters is limited and the optimum conditions for minimizing FAC effects, in most cases, cannot be achieved. Loss of material by FAC is, therefore, likely to occur and must be monitored. Since undesirable challenges to a plant's safety systems may result from piping system component failure, licensees maintain an FAC-related program to address failure prediction, inspection, and component repair/replacement.

The licensee indicated that they performed an FAC susceptibility evaluation using the CHECWORKS software to identify limiting components. Nondestructive exams are scheduled

and performed in accordance with the corrosion monitoring plan which uses the results of the CHECWORKS analysis as one of the inputs, along with industry experience, engineering judgment, and previous plant experience. The analysis used the changes in pressure, temperature, and flow velocity from current conditions to SPU conditions. The maximum predicted change in wear rate is less than one ten-thousandth of 1 inch per year. This level of change is considered insignificant. SPU has minimal impact on predicted wear rates. The licensee also stated in its application that the CHECWORKS model is updated after each outage with the newly acquired data.

In a request for additional information (RAI) dated January 10, 2008, the staff requested information on prior FAC inspections performed on feedwater heaters. In its response dated January 31, 2008, the licensee stated that all feedwater heaters have been inspected at least once since 2001. All of the measurements exceeded the minimum required thicknesses.

2.1.8.3 Conclusion

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

2.1.9 Steam Generator Tube Inservice Inspection

2.1.9.1 Regulatory Evaluation

Steam generator (SG) tubes constitute a large part of the RCPB. SG tube inservice inspection (ISI) provides a means for assessing the structural and leakage integrity of the SG. The NRC staff's review in this area covered the effects of changes in differential pressure, temperature, and flow rates resulting from the proposed SPU on plugging limits and potential degradation mechanisms (e.g., flow-induced vibration (FIV)). Specific review criteria are contained in SRP Section 5.4.2.2 (NUREG-0800) and other guidance provided in Matrix 1 of Section 2.1 of NRC document RS-001, "Review Standard for Extended Power Uprates." Additional review guidance is provided in RG 1.121 for SG tube plugging limits.

2.1.9.2 Technical Evaluation

CPSES, Unit 1 has Westinghouse Delta-76 (Δ76) SGs that were installed during refueling outage 12 (1RF12) in 2007. CPSES, Unit 2 has the original Westinghouse Model D-5 SGs. The Model D-5 SGs will continue to be in service when the proposed SPU is implemented. The SGs are designed to permit ISI of Class 1 and 2 components, including individual tubes. The design aspects that provide access for inspection and the proposed inspection program comply with the edition of ASME Code, Section XI, Division 1, Rules for Inspection and Testing of Components of Light Water-Cooled Plants, required by 10 CFR 50.55a(g). Both the Δ76 and the Model D-5 SGs have a number of inspection access openings that make it possible to inspect the tubes and implement a repair according to the techniques specified.

The Westinghouse Δ76 SGs have thermally treated Alloy 690 tubes. The Model D-5 SGs have thermally treated Alloy 600 tubes. It is expected that the SG tube materials will continue to perform acceptably, as in other plants with equivalent tube material and similar operating history.

The licensee evaluated all post-uprate system parameters in the existing SG analyses and concluded that the SGs will continue to satisfy all original design criteria under SPU conditions. The licensee performed an evaluation to address FIV under SPU conditions and the FIV impact on the SG tube bundle and installed tube-repair hardware. The licensee concluded that the tube bundle will not fail due to high-cycle fatigue, tube-to-tube impacts will not occur over the life of the plant, and all installed tube-repair hardware will maintain functional integrity. The tube plugging limit was evaluated by the licensee using the EPRI Flaw Handbook and determined to be conservative for SPU conditions. The staff performed independent analysis of the plugging limit and concurred with the licensee that the existing criteria remains appropriate. The SG tube plugging limit is the same as other similarly designed and operated units.

2.1.9.3 Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on SG tube integrity and concludes that the licensee has adequately assessed the continued acceptability of the plant's TSs under the proposed SPU conditions and has identified appropriate degradation management inspections to address the effects of changes in temperature, differential pressure, and flow rates on SG tube integrity. The NRC staff further 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 SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to SG tube ISI.

2.1.10 Steam Generator Blowdown System

2.1.10.1 Regulatory Evaluation

Control of secondary-side water chemistry is important for preventing degradation of SG tubes. The steam generator blowdown system (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 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 AOOs (main condenser in-leakage and primary-to-secondary leakage). The NRC's acceptance criteria for the SGBS are based on GDC-14, which requires that the RCPB be designed 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.

2.1.10.2 Technical Evaluation

The SGBS is designed to extract blowdown water from the secondary side of the SGs as a means of removing particulates and dissolved solids to optimize water chemistry in SGs.

During normal operation, continuous blowdown from each SG is routed to a common line outside the containment. The total blowdown flow then goes through the tube side of the heat exchanger and, after pressure reduction, through the filters and demineralizers. The cooled, demineralized, low-pressure blowdown then mixes with condensate; the combined flow is used as the coolant on the shell side of the heat exchanger. The coolant, which is now at a higher temperature because of the heat picked up from the hot blowdown, flows to the heater drain tank. The SGBS also provides samples of the secondary-side water in the SG. These samples are used for monitoring water chemistry and for detecting the amount of radioactive primary coolant leakage through the SG tubes.

Proper control of SG secondary-side chemistry reduces the probability of secondary-side-initiated SG tube degradation.

The licensee indicated that the increased steam and feedwater flow rates at SPU conditions do not significantly affect the concentration of impurities throughout the turbine cycle and the SGs. The SG chemistry is not affected by the SPU. Therefore, no changes to the SG blowdown flow rates or operating modes are required as a result of the SPU. The blowdown flow for CPSES, Units 1 and 2 is administratively limited to 600 gpm. The current blowdown rates are below the maximum system capacity values and are not expected to increase as a result of the SPU. Since the operating conditions of flow velocity, pressure, and temperature in the SG blowdown piping at SPU have not significantly changed from the original design parameters, the potential for erosion/corrosion or other types of failures are not expected to increase due to the SPU. The SGBS is included in the FAC program for monitoring of potential pipe-wall thinning due to erosion/corrosion.

2.1.10.3 Conclusion

On the basis of its review, the staff concludes that the SGBS remains adequate for SPU conditions because the blowdown flow, the SG secondary-side water chemistry, and the blowdown pressures and temperatures remain within the original system design. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the SGBS.

2.1.11 Chemical and Volume Control System

2.1.11.1 Regulatory Evaluation

The chemical and volume control system (CVCS) and boron recovery system (BRS) provide means for (a) maintaining water inventory and quality in the RCS, (b) supplying seal-water flow to the reactor coolant pumps (RCPs) and pressurizer auxiliary spray, (c) controlling the boron neutron absorber concentration in the reactor coolant, (d) controlling the primary water chemistry and reducing coolant radioactivity level, and (e) supplying recycled coolant for demineralized water makeup for normal operation and high-pressure injection flow to the emergency core cooling system (ECCS) in the event of postulated accidents. The NRC staff reviewed the safety-related functional performance characteristics of the CVCS components. The NRC's acceptance criteria are based on (1) GDC-14, that requires that the RCPB be designed to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture, and (2) GDC-29, that requires that the reactivity control systems

be designed to assure an extremely high probability of accomplishing their safety functions in event of AOOs. Specific review criteria are contained in SRP Section 9.3.4.

2.1.11.2 Technical Evaluation

The primary function of the CVCS is to maintain RCS water inventory, boron concentration, and water chemistry. In addition, the CVCS provides for boric acid addition and removal, chemical additions for corrosion control, reactor coolant cleanup and degasification, reactor coolant makeup, and processing of reactor coolant letdown.

During plant operation, reactor coolant letdown is taken from the cold leg through the regenerative heat exchanger and then through letdown control valves. The regenerative heat exchanger reduces the temperature of the reactor coolant and the control valves reduce the pressure. The letdown is cooled further in the tube side of the letdown heat exchanger and subsequently passes through the purification filter. Flow continues through the purification ion exchangers, where ionic impurities are removed, and enters the volume control tank (VCT). The charging pumps take suction from the VCT and return the coolant through the regenerative heat exchanger to the RCS in the cold leg, downstream of the RCP.

Under SPU conditions, the licensee indicated that there will be no changes to the charging flow rates or temperatures. There is also no change to the current operating or design pressures of the CVCS. However, the RCS cold-leg temperatures will decrease slightly to 558 °F, but remains within the design temperatures of the respective components in the letdown portion of the system. This will result in a slightly lower temperature for the letdown line since the CVCS system takes suction from the cold leg. The licensee concluded that the slightly lower temperature of the letdown line does not affect the performance of the letdown coolers because they remain bounded by current operation and design specifications. In addition, the licensee reported that no changes to the makeup requirement are required under SPU conditions. Boration capability of the CVCS under SPU conditions was evaluated and determined to be acceptable with margin remaining in the flow, volume, and time limits.

2.1.11.3 Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the CVCS and BRS and concludes that the licensee has adequately addressed changes in the temperature of the reactor coolant and their effects on the CVCS and BRS. The NRC staff further concludes that the licensee has demonstrated that the CVCS and BRS will continue to be acceptable and will continue to meet the requirements of GDC-14 and GDC-29 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the CVCS.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

2.2.1.1 Regulatory Evaluation

SSCs important to safety at nuclear power plants 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 at CPSES, Units 1 and 2 are adequately protected from the effects of pipe ruptures. The NRC 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 NRC staff's review focused on the effects that the proposed SPU may have on items (1) through (4) above. The NRC staff's 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.

2.2.1.2 Technical Evaluation

The licensee's current licensing basis for CPSES required pipe rupture analysis in accordance with SRP Section 3.6.2. The CPSES current structural design basis includes postulated ruptures in high and moderate energy piping. CPSES's acceptance criteria for postulating pipe breaks in high and moderate energy piping are contained in Final Safety Analysis Report (FSAR) Section 3.6B and are in accordance with Branch Technical Position (BTP) MEB 3-1 of SRP Section 3.6.2. Consideration was also given to design features that protect essential equipment from the dynamic effects of pipe whip and jet impingement of postulated pipe breaks both inside and outside containment. The current structural design basis of CPSES implements the guidance of GDC-4 to include the application of LBB methodology described in NUREG-1061 Volume 3 and eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping and 10-inch and larger reactor coolant loop (RCL) branch lines (including the pressurizer surge line, the accumulator line, and the RHR line). The validity of the LBB methodology under the proposed SPU conditions is contained in SPULR Section 2.1.6. The staff's evaluation of LBB is documented in Section 2.1.6.

The LBB is applicable to CPSES for the main loop piping, pressurizer surge line, accumulator, and RHR lines. In response to the staff's RAI, the licensee confirmed that for SPU conditions pipe-break evaluations included RCL branch line pipe breaks (BLPBs) for the 6-inch safety-injection line to the hot leg and the 4-inch pressurizer spray line from the cold leg. The licensee also confirmed that for SPU conditions, secondary-side pipe-break evaluations for the main steam line (MS), the main feedwater (FW) line, and auxiliary feedwater (AFW) line were considered. The licensee confirmed that the pipe-break evaluations for SPU conditions were performed in accordance with the existing licensing and design basis for CPSES, Units 1 and 2. Based on its review of applicable pipe breaks at SPU conditions, the licensee found that, with the exception of the FW piping, the existing design-basis analyses used bounding input loads

that envelop loads from SPU conditions and, therefore, the existing pipe-break, jet impingement, and pipe-whip evaluations remain valid for the SPU conditions. With respect to the FW piping, in its response to staff's RAI and during a conference call between the staff and the licensee, the licensee stated that a preliminary FW piping analysis has been completed which shows that resulting stresses are within the allowable acceptance limits for pipe breaks as defined in FSAR Section 3.6B.2 and BTP MEB 3-1 of SRP Section 3.6.2. Therefore, reasonable assurance exists that no new or revised postulated pipe-break locations are required for FW piping due to the SPU. The licensee in its response also stated the preliminary FW pipe-break evaluation indicates that there are no new or modified pipe-whip restraints, and no new or modified pipe supports required with regard to FW pipe-break loadings due to higher SPU conditions in the FW system (for FW pipe support modifications due to other than pipe-break loadings, see Section 2.2.2.2.2). The staff finds the licensee's response with regard to FW pipe-break evaluation acceptable as it provides reasonable assurance that the FW piping integrity is adequate for pipe-break loads due to higher SPU conditions.

The licensee, using methods and criteria from the existing licensing basis and design-basis analyses on record, found that the pipe-break evaluations for SPU conditions of applicable piping systems did not result in new or revised break/crack locations, and the existing design basis for pipe break, jet impingement, pipe whip, and environmental considerations remain valid for the SPU. Upon confirmation of preliminary calculations of the FW piping, the staff finds the licensee's pipe-break evaluations adequate and acceptable as they meet the design-basis acceptance criteria of FSAR Section 3.6B.2 and are in accordance with BTP MEB 3-1 of SRP Section 3.6.2.

2.2.1.3 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 SPU. Upon confirmation of preliminary calculations of the FW piping, the NRC 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 SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the determination of rupture locations and dynamic effects associated with the postulated rupture of piping.

2.2.2 Pressure-Retaining Components and Component Supports

2.2.2.1 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 GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15. The NRC staff's review focused on the effects of the proposed SPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The NRC 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 NRC staff's review also included a comparison of the resulting stresses and fatigue cumulative usage factors (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.

2.2.2.2 Technical Evaluation

2.2.2.2.1 Nuclear Steam Supply System Piping, Components, and Supports

Nuclear steam supply system (NSSS) piping, which is the RCS piping, consists of four heat-transfer piping loops connected in parallel to the reactor pressure vessel (RPV). The licensee's SPULR indicates that the CPSES current design bases for NSSS piping, components, and supports are contained in FSAR Sections 3.1, 3.2, 3.7N, 3.9N, and 5.4, and meet the requirements of 10 CFR 50.55(a), and GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15. The code of record for RCL piping is the ASME Code, Section III, 1977 Edition and Addenda through Summer 1979. The code of record for RCL supports is the ASME Code, Section III, 1974 Edition and Addenda through Summer 1974.

The licensee evaluated the existing design-basis analyses for RCL piping and associated branch piping, RCL primary equipment supports, and pressurizer surge line to assess the impact associated with the implementation of SPU. Specifically, the following items were evaluated by the licensee for the SPU program:

- RCL piping system LBB loads for LBB evaluation
- RCL loss-of-coolant accident (LOCA) analysis using Loop LOCA hydraulic forces and the associated Loop LOCA RPV motions
- RCL piping stresses
- RCL piping displacements at the junction of the centerline of the RCL piping and the branch nozzle connections of the auxiliary piping systems to the RCL and impact on auxiliary piping systems
- Primary equipment nozzle loads
- Pressurizer surge line piping analysis including the effects of thermal stratification
- Primary equipment support loads (RV, SG, and RCP)

SPULR Tables 2.2.2.1-1 and 2.2.2.1-2 (CPSES, Unit 1 and CPSES, Unit 2, respectively) provide RCL maximum stress summaries and CUFs with comparisons to allowable values for SPU conditions. All stresses and CUFs are within allowable values and, therefore, acceptable. In response to the staff's RAI, the licensee submitted current RCL maximum stress summaries and fatigue CUFs for comparison to values corresponding to current power level. There are no significant changes shown from current to SPU conditions. The licensee evaluated primary equipment nozzle loads which were found to be acceptable for the SPU. The primary equipment support loads (RV, SG, RCP, and pressurizer supports) were also evaluated by the licensee for SPU conditions and the licensee indicated that they met the required design-basis criteria for equipment support stresses.

The licensee, using the current plant design-basis methodology and acceptance criteria, has evaluated the structural integrity of the NSSS piping and supports, the primary equipment nozzles, and the primary equipment supports. Therefore, based on its review as summarized above, the staff concurs with the licensee that the NSSS piping, components, and supports are structurally adequate for the proposed SPU.

2.2.2.2.2 Balance-of-Plant Piping, Components, and Supports

The licensee evaluated the effects of the proposed SPU implementation on the BOP and non-Class 1 piping and supports inside and outside containment. Section 2.2.2.1 covered Class 1 RCS piping and supports up to the Class 1 boundary. The licensee's SPULR indicates that CPSES current design bases for BOP piping, components and supports meet the requirements of 10 CFR 50.55(a)(1), and GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15 as documented in CPSES FSAR Sections 3.2, 3.7B, and 3.9B. The licensee evaluated BOP piping and support systems to assess the impact of operating temperature, pressure, and flow-rate changes that will result due to the implementation of SPU in accordance with the current design-basis criteria. For BOP ASME Code Class 2 and 3 piping systems, the code of record for piping is ASME Code, Section III, 1974 Edition up to and including the Summer 1974 Addenda and for supports is ASME Code, Section III, Subsection NF, 1974 Edition up to and including the Winter 1974 and the criteria of FSAR Section 3.9N.1. For BOP non-ASME piping and supports, the code of record is the ANSI 31.1 Code, 1973 Edition up to and including the Winter 1974 Addenda. Included in the licensee's evaluations for SPU conditions are the following BOP piping and support systems: MS, FW, condensate, extraction steam, heater drains, SG blowdown, AFW, SFP cooling, RHR, component cooling, service water, containment spray, chemical volume and control, safety injection, and auxiliary steam.

The licensee, in evaluating piping stress levels, piping supports, and loadings for nozzle and containment penetration acceptability at SPU conditions, established "change factors" by dividing SPU conditions of temperature, pressure, and flow over current conditions of temperature, pressure and flow rate obtained from heat-balance diagrams and calculations. For change factors less than or equal to 1.00, where the current condition envelops or equals the SPU condition, the piping and support system was concluded to be acceptable for SPU conditions. In its January 14, 2008, response to staff's RAI, the licensee indicated that for piping systems containing "change factors" greater than 1.00 (portions of the FW, condensate, FW heater drains, extraction steam, and AFW piping) detailed evaluations were performed using simplified hand calculation methods (manually increasing existing stresses and loads) or

by performing more detailed computer analyses to demonstrate piping and pipe support component acceptability. A summary of the maximum stress levels for systems requiring detailed evaluations for current and SPU conditions including a comparison to code-of-record-allowable stress levels is provided in Table 2.2.2.2-1 (CPSES, Unit 1) and Table 2.2.2.2-2 (CPSES, Unit 2) of the SPULR. For each piping system listed in these tables, the stresses reported are at the most critical locations of the piping system, corresponding to the piping location containing the highest allowable stress ratio (SPU stress divided by the allowable stress). These critical stress locations may be at equipment nozzles, containment penetrations, or at any in-line piping component (e.g., valve, elbow, or reducer) where the maximum stress occurs within the analytical boundaries of the piping stress model. The revised stress levels at SPU conditions are shown to be within code-of-record-allowable stress levels and, therefore, are acceptable. In its response to the staff's RAI, the licensee provided summaries which demonstrate that for SPU conditions, loads and/or stresses for nozzles and containment penetrations that were most affected by the SPU are within design-basis-allowable values and therefore acceptable. With regard to FW pump nozzles and their acceptability for the higher SPU fluid transient loads, the licensee in its response to the staff's RAI, stated that the pump vendor has evaluated the SPU revised loads and has found them acceptable (Reference 15). In its response to NRC staff's RAIs, the licensee also provided summary tables of the vendor evaluation which show that the pump, pump nozzles, and pump support acceptable by meeting design-basis-allowables. Therefore, the licensee concluded that no piping modifications (physical piping re-routes) are required due to the SPU. In its response to the staff's RAI, the licensee indicated that the CPSES, Unit 1 FW piping system is the only system that will require pipe support modifications to withstand water hammer loads from fluid transients due to higher flow rate at SPU conditions. The licensee provided details of modification for approximately eight existing pipe supports and one new support (all related to the CPSES, Unit 1 FW system) required to meet design-basis-allowable values for SPU conditions. The licensee also stated that support modifications required for the SPU will be completed prior to restarting the plant for SPU implementation. The staff finds the licensee's response acceptable as it has demonstrated that BOP piping and pipe supports with the included pipe support modifications will satisfy code of record and design-basis requirements for piping and pipe supports.

In its response to the staff's RAI with regard to thermal expansion, on the issue that piping could potentially expand due to higher SPU temperature in affected systems and impose an unanalyzed condition that could potentially overstress piping and supports or otherwise damage SSCs, the licensee responded that during the planned baseline walkdown to be performed for piping vibration, piping systems subjected to a temperature increase associated with the SPU will be inspected to identify any locations where there is a potential for unacceptable thermal expansion interaction. The licensee estimated that the increases in thermal expansion displacements associated with the proposed SPU are less than 1/16 of an inch and, therefore, of no significant concern. In addition, the licensee stated that during startup of the SPU, piping systems subjected to a temperature increase will be observed to identify any unanticipated unacceptable conditions. The staff finds the licensee's response acceptable as the licensee has properly addressed the issue that piping thermal expansion at a higher SPU temperature will not impose an unanalyzed condition that could potentially overstress piping and supports or otherwise damage SSCs.

With respect to FIV at the higher SPU flow rates for affected systems, the licensee in its response to the staff's RAI, indicated that CPSES has developed a comprehensive plan to

address FIV in piping affected by the proposed SPU. The plan began with the development of a program to address scope, method, evaluation, and acceptance criteria. The scope includes all piping with increased flow rates resulting from the SPU (including MS, FW, condensate, extraction steam, and FW heater drains). The method is to perform a series of walkdowns spanning from the current plant condition to the completion of power ascension testing following implementation of the SPU. Piping systems which will experience increased flow rates due to the SPU will be inspected using visual methods during SPU implementation. Initially simple tools and methods as described in the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code), Part 3 will be used. If warranted, instrumented data acquisition will be employed to record data. In its RAI response, the licensee stated that the acceptance criteria for all piping evaluations will be in accordance with ASME OM Code, Part 3. The staff finds the licensee's plan to monitor piping FIV adequate and acceptable as the licensee has verified that the methodology for evaluation and acceptance criteria for all in-scope piping (see above) for vibration issues will be in accordance with ASME OM Code, Part 3.

Based on the staff's review of CPSES's evaluations of BOP piping, components, and supports for the SPU as summarized above, the staff finds the licensee's methodology acceptable as it conforms with the codes of record and plant design-basis requirements and concurs with the licensee's conclusion that the BOP piping, components, and supports with the planned support modifications and additions will maintain their structural integrity for SPU conditions.

2.2.2.2.3 Reactor Vessel and Supports

The RPV is the principal component of the RCS and contains the heat-generating core, core support structures, control rods, and other components directly associated with the core. The RPV primary outlet and inlet nozzles provide for the exit of heated coolant and its return to the RPV for recirculation through the core. The CPSES RPV is cylindrical, with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. CPSES FSAR Section 5 contains the current licensing and design basis for the RPV and its supports. The RPV and its supports are designed to withstand stresses originating from various operating design transients described in FSAR Section 3.9N.1.1 and FSAR Table 3.9N-1. The RPV is designated Safety Class 1, as stated in FSAR Section 5.3.1. Design and fabrication of the RPV was carried out in accordance with the ASME Code, Section III, Class 1 requirements. The RPV supports are designed to meet the same Safety Class designation as the components they support. The RPV supports are classified as QA Category 1 and Seismic Category I. The code of record for the RPV is ASME Code, Section III, Division 1, 1971 Edition through Winter 1972. The CPSES, Unit 1 RPV closure head was replaced in the spring 2007 outage. The replacement head was designed and fabricated as a one-piece forging in accordance with the ASME Code, Section III, 1989 Edition with no addenda.

The licensee performed its evaluations for the CPSES RPV at SPU conditions in accordance with the current plant codes of record using the current design-basis RV stress report for each unit. Stress-intensity ranges and CUFs due to changes in design transients were evaluated and compared to the acceptance criteria of the current code of record, ASME Code, Section III, Class 1 requirements. SPULR Tables 2.2.2.3-1 and 2.2.2.3-2 (CPSES, Unit 1 and CPSES, Unit 2, respectively) provide summaries of the maximum ranges of stress intensity and maximum CUFs from the RV evaluations at SPU conditions. In response to the staff's RAI, the licensee resubmitted these tables to show current analyses summaries for comparison.

Stress-intensity ranges and CUFs for CPSES, Unit 1 remained unchanged from those calculated in the current vessel evaluations. For CPSES, Unit 2, the stress-intensity ranges are shown unchanged while CUFs at some locations increased slightly due to changes in transients that apply to CPSES, Unit 2 SPU. All of the regions of the RV are shown to meet the primary-plus-secondary stress-intensity allowable of 3Sm (3 times the design stress-intensity value) as required by ASME Code, Section III, NB-3222.2 with the exception of the bottom head-mounted instrument tubes (BMI) (both units) which exceeded the 3Sm limit and the licensee indicated that it was qualified by the elastic-plastic analysis, as allowed by NB-3228.3. In its response to the staff's RAI, the licensee provided a summary of the results of the elastic-plastic evaluation which shows that the special rules for exceeding 3Sm, as provided by (a) through (f) of Subparagraph NB-3228.3 have been met for current and SPU conditions. The staff finds the licensee's stress and CUF RV evaluation and results acceptable as it was performed in accordance with the plant design basis and met the code of record criteria requirements.

Review of the licensee's summary evaluation for the BMI guide tubes and flux thimbles at SPU conditions of both units presented in SPULR Section 2.2.7 reveals compliance with the applicable ASME Code, Section III criteria and, therefore, is acceptable.

The licensee also reviewed LOCA hydraulic forces and concluded that they remained unchanged from the previously evaluated forces. In addition, seismic loads are unaffected by the SPU.

The licensee also evaluated the RV supports using the existing design-basis calculations and found them acceptable for SPU conditions.

On the basis of its review, as summarized above, the staff concurs with the licensee's conclusion that the current design of CPSES's RPV and supports for the SPU remains in compliance with 10 CFR 50.55a; GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15; and the code of record, ASME Code, Section III, Division 1.

2.2.2.2.4 Control Rod Drive Mechanism

The CRDMs are located on the dome of the RPV head and are coupled to the RCCAs. The primary function of the CRDMs is to insert, withdraw, or hold stationary RCCAs within the core to control average core temperature and to shut down the reactor. The CPSES, Unit 1 RPV head was replaced in the spring 2007 outage and was designed and fabricated in accordance with the ASME Code, Section III, 1989 Edition with no addenda. CPSES, Unit 1 utilizes the Westinghouse Model L-106C CRDMs. The code of record for the CPSES, Unit 2 Model L-106A CRDMs is the ASME Code, Section III, 1974 Edition through Summer 1974 Addenda.

The licensee evaluated the structural integrity of the pressure retaining sections of the CRDM assembly under SPU conditions. The pressure vessel of the CRDM assembly is part of the RCPB and it contains the latch housing and the rod travel housing which are connected by a threaded, seal-welded maintenance joint. The closure at the top of the rod travel housing is a threaded cap with a canopy seal weld for pressure integrity. The latch housing is the lower portion of the CRDM pressure vessel and encloses the latch assembly. The licensee's evaluation of these components for SPU conditions is summarized in SPULR Section 2.2.2.4.

The licensee employed the current design basis and codes of record to evaluate the RCPB structural integrity of the CPSES CRDMs using the NSSS operating parameters of SPU (SPULR Section 1.1) and the SPU NSSS design transients (SPULR Section 2.2.6) for the CPSES, Units 1 and 2. Applicable loadings include pressure, deadweight, seismic, thermal, and transient loads. Pressure, deadweight and seismic loads are unaffected by the SPU. The hot-leg maximum temperature (RPV outlet temperature) is 620.4 °F for the SPU and is bounded by the 650.0 °F used in the current design analyses of record. The licensee compared the SPU NSSS design transients against those used in the current analyses to evaluate the CPSES CRDMs. The licensee noted that for CPSES, Unit 1 there are no changes to the design transients due to the SPU. For CPSES, Unit 2, the difference between the SPU transients and the current design-basis analysis transients are that there are 33 additional SPU transients and there are temperature and pressure range differences between the SPU and existing design-basis NSSS design transients. The licensee reconciled the differences between the SPU design transients and the design-basis transients and recalculated stress intensities and CUF values to include SPU conditions using the current design-basis methodology. In its response to the staff's RAI, the licensee resubmitted SPULR Tables 2.2.2.4-1 through 2.2.2.4-6. These tables show current, SPU, and code-allowable stress intensities plus CUF values for the CRDM pressure vessel assembly and its components for both units. For CPSES, Unit 1, at two locations where the primary-plus-secondary stress-intensity-allowable limit of 3Sm, as required by ASME Code, Section III, NB-3222.2, was exceeded, the licensee has noted that elastic-plastic analysis was performed to show acceptability. In its response to the staff's RAI, the licensee provided a summary of the results of the elastic-plastic evaluation which shows that the special rules for exceeding 3Sm, as provided by (a) through (f) of Subparagraph NB-3228.5 have been met. All stress and CUF values meet the allowables defined by the criteria requirements of the design-basis codes of record for the CPSES, Units 1 and 2 CRDMs.

The licensee, using the current plant design-basis methodology to evaluate the pressure boundary components of the CRDMs, has demonstrated that these components meet the code of record criteria requirements for structural integrity. Therefore, the staff based on its review as summarized above, concurs with the licensee that the CPSES pressure boundary components of the CRDMs are structurally adequate for continuous operation under the proposed SPU.

2.2.2.2.5 Steam Generators and Supports

The four SGs that each of the two CPSES units employ are Westinghouse Model Δ76 for CPSES, Unit 1 and Westinghouse Model D-5 for CPSES, Unit 2. The current licensing and design basis for the SGs is contained in FSAR Sections 3.9N, 5.1, and 5.4.2, and FSAR Table 5.2-1. The current licensing and design basis for the SG supports are contained in FSAR Sections 5.4.14.2.2 and 5.4.14.2, and FSAR Table 5.4-18. The SGs were designed and fabricated in accordance with the requirements of ASME Code, Section III, Division 1, 1971 Edition through Summer 1973 Addenda (Reference: FSAR Table 5.2-1). The licensee used the design-basis codes of record to evaluate the structural adequacy of the SGs pressure boundary and the internal components and SG supports for the new SPU conditions.

The CPSES, Unit 1 D-4 SGs were replaced at the 1RF12 outage with Δ76 SGs which include many design upgrades. The licensee evaluated primary- and secondary-side SG components of CPSES, Unit 1 to determine the structural integrity impact resulting from changes in the

operating and design transient parameters (SPULR Sections 1.1 and 2.2.6) associated with the SPU. The licensee's evaluations are summarized in SPULR Section 2.2.2.5. The licensee in its staff RAI response provided stress and fatigue evaluation summaries for CPSES, Unit 1 SG components. Review of the licensee's evaluations show that the stress ranges and fatigue results presented in the current analyses of these components remain valid for the SPU. The evaluation summaries show stress ranges and fatigue CUFs within ASME code of record allowable acceptance limits with the exception of a few locations which could not meet the ASME Code-allowable limit of 3Sm for primary-plus-secondary stress-intensity range. The licensee indicated that these locations have shown to be acceptable in the current design calculations (which are also applicable for SPU conditions) either by elastic-plastic analysis or by plastic analysis in accordance with ASME Code, Section III, Subsection NB.

The licensee also evaluated the primary and secondary sides of the CPSES, Unit 2 D-5 model SG components to determine the structural integrity impact resulting from changes in the operating and design transient parameters (SPULR Sections 1.1 and 2.2.6) associated with the SPU. The licensee's evaluations are summarized in SPULR Section 2.2.2.5 and in its staff RAI responses. The licensee submitted maximum stress-intensity ranges and fatigue CUFs for current and SPU conditions for comparison. There are small changes due to the SPU mainly in the fatigue CUFs due to changes in SPU design transients. All CUFs are shown to be below the acceptance allowable of 1. At most of the locations, the stress-intensity ranges evaluated for the SPU did not change and at some locations changed slightly. Locations where stress-intensity ranges did not meet the 3Sm limit for primary-plus-secondary stress intensity, the licensee has indicated that these locations have been qualified by meeting the requirements of ASME Code, Section III, Subsection NB Class 1 elastic-plastic or plastic analysis and are, therefore, acceptable.

The licensee performed thermal-hydraulic analyses to evaluate the effects of tube-wall local dryout (departure from nucleate boiling (DNB), which could result in excessive build-up of tube scale), hydrodynamic instability, and moisture carryover. From the evaluations the licensee performed, it concluded that the thermal-hydraulic operating characteristics for the SPU are acceptable and there are no concerns of thermal performance deficiency, local dryout of tube walls, hydrodynamic instability or excessive moisture carryover.

The licensee's evaluations of the SG tubes for FIV and tube wear are summarized in SPULR Section 2.2.2.5 and in the licensee's responses to staff RAIs. Evaluations of FIV and tube wear were performed for fluid-elastic stability and amplitudes of tube vibration due to turbulences. Review of licensee's summary evaluations shows that for both CPSES units, the increase in fluid-elastic stability ratio is still less than the allowable of 1.0 at SPU conditions and is, therefore, acceptable. Hence, the staff concurs with the licensee's conclusion that the increase in fluid-elastic stability ratio due to higher SPU flow rate will not produce any significant vibration or tube-wear effects.

With regard to the SG dryer and its support structures, the licensee in its response to the staff's RAI, provided a justification as to why FIV is not an issue with these components at SPU conditions. The licensee indicated that Industry experience of PWR SGs at roughly 28 domestic plants operating 92 SGs with the same or similar types of dryer and support structures as those in service at CPSES, Units 1 and 2 have no reported operational failures or issues related to FIV. The licensee also provided a comparison with the boiling water reactor (BWR) plants

which have reported FIV-related issues in the steam dryer region. While steam flows in a BWR could reach speeds in excess of 100 fps [feet per second] (with a redirection of flow path to the steam outlet nozzles), steam flows in the dryer region of the CPSES, Units 1 and 2 SGs are approximately 4 fps maximum (with a direct steam flow path to the SG steam outlet nozzle) under the SPU dryer flow conditions. The staff finds the licensee's response acceptable as it provides reasonable assurance that there is very low FIV potential impact in the steam dryer, its support structures, and adjacent area for the two CPSES units under the SPU dryer flow conditions.

The licensee evaluated the SG supports for SPU conditions and indicated that they met the required design-basis criteria for equipment support stresses.

The licensee, using the current plant design-basis methodology to evaluate the SGs and their supports, has demonstrated that these components meet the codes of record and design-basis criteria requirements. Therefore, the staff, based on its review as summarized above, concludes that the effects of the proposed SPU at the CPSES, Units 1 and 2 do not adversely affect the structural integrity of the SGs and their supports.

2.2.2.2.6 Reactor Coolant Pumps and Supports

The current licensing and design basis for the RCPs are contained in FSAR Sections 3.9N, 5.1, and 5.4.1, and FSAR Table 5.2-1. The current licensing and design basis for the RCP supports is contained in FSAR Sections 3.9N and 5.4.14. The RCPs were designed and fabricated in accordance with the requirements of ASME Code, Section III, Division 1, 1971 Edition through Summer 1973 Addenda.

The licensee evaluated the RCS piping and supports (RPV supports, SG supports, RCP supports, and the pressurizer supports) for SPU parameters and SPU NSSS design transients. The staff's review of the RCS piping and supports is presented in Section 2.2.2.2.1. SPU NSSS performance capability working group (PCWG) parameters are provided in SPULR Tables 1.1-1 and 1.1-2 for CPSES, Unit 1 and CPSES, Unit 2 respectively. In its response to the staff's RAI, the licensee resubmitted these tables to show current licensed PCWG parameters for comparison. The licensee compared the design loads developed from SPU conditions to those used in the existing design-basis analyses of record and determined that design loads from the existing analyses bound the SPU design loads. The licensee also compared the recalculated SPU NSSS design transients, which are presented in SPULR Section 2.2.6, to those used in the existing RCP analyses and noted that there are transients and temperature and pressure range differences between the SPU and the existing analyses transients for CPSES, Unit 2, while there are no design transient differences for CPSES, Unit 1. The licensee recalculated stress amplitudes and CUFs for affected RCP components at SPU design transients for Unit 2. The staff reviewed the licensee's RCP component structural evaluations presented in SPULR Section 2.2.2.6. SPULR Table 2.2.2.6-1 contains SPU stress amplitudes and CUFs. SPU stress-intensity ranges are presented in SPULR Table 2.2.2.6-2. The Unit 1 fatigue and stress intensity evaluations remained unaffected by the SPU. Some of the stress-intensity ranges and fatigue evaluation stress amplitudes and CUFs factors increased for the CPSES, Unit 2 SPU, but all remained within allowable acceptance limits.

The licensee evaluated the RCP supports for SPU conditions and indicated that they met the required design-basis criteria for equipment support stresses.

The licensee, using the current design basis and code of record, has adequately addressed the SPU effects on the RCPs and supports. The staff based on its review as summarized above, concludes that the SPU does not adversely affect the structural integrity of the RCPs and their supports and, therefore, is acceptable.

2.2.2.2.7 Pressurizer and Supports

The current licensing and design basis for the pressurizer is contained in FSAR Sections 3.9N and 5.4.10, and FSAR Table 5.2-1. The current licensing and design basis for the pressurizer supports is contained in FSAR Section 5.4.14.2.4 and Table FSAR 3.9N-17 (pressurizer support allowable stresses and loads). The pressurizer applicable code of record is the ASME Code, Section III, 1974 Edition.

The licensee evaluated the pressurizer and its supports for SPU parameters summarized in SPULR Section 1.1 and SPU NSSS design transients summarized in SPULR Section 2.2.6. The licensee reviewed and compared the design loads developed from SPU conditions to those used in the existing design-basis analyses of record and determined that design loads from the existing analyses bound the SPU design loads. The licensee also reviewed NSSS SPU design transients and noted that the majority of the NSSS design transients did not change. Others were enveloped by the existing analysis design transients. The licensee in its response to the staff's RAI, indicated that based on evaluations performed, the current pressurizer design stress reports did not require any changes due to SPU conditions. Therefore, the staff concurs with the licensee that the existing calculated stresses and fatigue evaluations for the pressurizer and its components remain unaffected by the SPU and meet ASME Code-allowable limits as summarized in SPULR Tables 2.2.2.7.2-2 and 2.2.2.7.2-3.

With respect to pipe supports, the licensee indicated that they have been evaluated and found to be within design-basis limits for SPU conditions.

In SPULR Section 2.2.2.6, the licensee indicated that the pressurizer surge-line evaluation was performed in accordance with the acceptance criteria of the ASME Code, Section III, Subsection NB, 1986 Edition, and includes the fatigue evaluation and the effects of thermal stratification. The licensee's summary evaluation of the surge-line thermal stratification due to the SPU is presented in SPULR Section 2.2.2.1. The licensee evaluated the surge-line thermal stratification pipe loads due to the SPU for both units and determined that the SPU has no adverse impact on the thermal stratification and fatigue results for the currently documented surge-line evaluation. The staff reviewed the licensee's evaluation on the surge-line stratification and concurs with the licensee that the proposed SPU has no significant structural impact on the surge-line stratification.

The licensee, using the current plant design-basis methodology and acceptance criteria, has evaluated the structural integrity of the pressurizer and its supports under SPU conditions. Therefore, the staff based on its review as summarized above, concurs with the licensee that the CPSES pressurizer and its supports are structurally adequate for continued operation under the proposed SPU.

2.2.2.3 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 NRC staff concludes that the licensee has adequately addressed the effects of the proposed SPU on these components and their supports. Based on the above, the NRC staff further concludes that the licensee has demonstrated that pressure-retaining components and their supports will continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

2.2.3 Reactor Pressure Vessel Internals and Core Supports

2.2.3.1 Regulatory Evaluation

RPV internals consist of all the structural and mechanical elements, including core support structures. The NRC staff reviewed the effects of the proposed SPU on the design input parameters and the design-basis loads and load combinations for the RIs 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 FIV for safety-related and non-safety-related RI components and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC 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 AOOs. 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.

2.2.3.2 Technical Evaluation

The CPSES evaluations of RPV core support structures and non-core support structures (all internal structures that are not core support structures) for the effects of the proposed SPU are summarized in Section 2.2.3 of the SPULR. The current licensing and design basis for the RPV internals is contained in FSAR Sections 3.9N.5, 3.9N.2.3, and 5.2.3.1, and FSAR Tables 5.2.3-3 and 3.9N-11. SPULR indicates that CPSES, Units 1 and 2 RPV internals were designed and built prior to the implementation of Subsection NG and, therefore, a plant-specific stress report

on the RPV internals was not required. The licensee though states analyses for the RPV internals have been performed that meet the intent of the ASME Code.

According to the licensee, both generic and plant-specific structural analysis evaluations have been performed for the RPV internals that meet the intent of the ASME Code. These analyses were used as the basis for evaluating critical CPSES RPV internal components for SPU RCS conditions and revised NSSS design transients. The licensee performed specific evaluations at the SPU conditions for the following, most limiting RI components: upper core plate, lower support plate, lower core plate, lower support column, core barrel, and baffle-former bolts. Summaries of results of these evaluations for SPU conditions showing maximum stress-intensity ranges and fatigue CUFs are presented in SPULR Table 2.2.3-6. In response to the staff's RAI, the licensee resubmitted Table 2.2.3-6 to show values both at existing and SPU conditions. Where the primary-plus-secondary stress-intensity-allowable limit of 3Sm, as specified by ASME Code, Section III, NB-3222.2, was exceeded at SPU conditions, in its response to the staff's RAI, the licensee stated that acceptability has been shown by elastic-plastic analysis and provided a summary of the results of the elastic-plastic evaluation which shows that the special rules for exceeding 3Sm, as specified by (a) through (f) of Subparagraph NB-3228.3 have been met.

The licensee also evaluated the RPV internals components for FIV due to the SPU and summarized the analyses results of critical components in SPULR Tables 2.2.3-4 and 2.2.3-5. The maximum calculated alternating stresses are very small compared to the endurance limit of the component material. Therefore, it is shown that fatigue due to FIV is not an issue at SPU conditions.

The licensee has demonstrated that overall, the maximum stress-intensity ranges and CUFs for the RPV internals continue to meet ASME-acceptable limits. Therefore, based on its review as summarized above, the staff concludes that the effects of SPU do not adversely affect the structural integrity of the RPV internal components and core support structures.

2.2.3.3 Conclusion

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

2.2.4 Safety-Related Valves and Pumps

2.2.4.1 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 OM Code, as applicable. The NRC staff's review focused on the effects of the proposed SPU on the required functional performance of valves and pumps at

CPSES, Units 1 and 2. The review also covered any impacts that the proposed SPU might have on the licensee's motor-operated valve (MOV) programs related to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance"; GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves"; and GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." The NRC 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 (1) GDC-1, insofar as it requires those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-37, GDC-40, GDC-43, and GDC-46 insofar as they require that the ECCS, the containment heat removal (CHR) system, the containment atmospheric cleanup systems, and the cooling water system, respectively, be designed to permit appropriate periodic testing to ensure the leak-tight integrity and performance of their active components; (3) GDC-54, insofar as it requires that piping systems penetrating containment be designed with the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits; and (4) 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section must meet the inservice testing (IST) program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6, and Power Uprate Review Standard RS-001.

2.2.4.2 Technical Evaluation

In its submittal dated August 28, 2007, requesting a license amendment to operate CPSES at SPU conditions, the licensee discussed its evaluation of safety-related valves and pumps to perform their intended functions under SPU conditions. The NRC staff has reviewed the licensee's evaluation of the impact of SPU conditions on safety-related valves and pumps at CPSES. This review is summarized in the following paragraphs.

In response to GL 89-10 and GL 96-05, CPSES established a testing and surveillance program for MOVs. In a letter dated October 6, 1995 (NRC Inspection Report 50-445/95-19 and 50-446/95-19), the NRC concluded that the MOV program for CPSES was acceptable in scope and precision. In a letter dated September 30, 1998, the NRC enclosed the SE for CPSES's response to GL 96-05, and stated that CPSES had established an acceptable program to periodically verify the design-basis capability of the safety-related MOVs through the actions described in its submittals. In its request for the SPU license amendment, the licensee described its evaluation of the MOVs within the scope of GL 89-10 at CPSES for the effects of the proposed SPU, including those related to pressure locking and thermal binding as addressed in GL 95-07. The licensee's review of affected systems indicates that the existing maximum operating conditions (e.g., flow rates, pressures and temperatures) remain valid for the SPU. Therefore, no changes were identified to the design functional requirements for the GL 89-10 MOVs. The MOVs were also evaluated for pressure locking and thermal binding under SPU conditions, and no new MOVs were determined to susceptible to pressure locking or thermal binding.

CPSES has in place a program for testing, inspection, and maintenance of air-operated valves (AOVs). The licensee has reviewed system level design-basis calculations for the RCS, CVCS,

safety-injection system, RHR system, AFW system, component cooling water (CCW) system, demineralized and reactor makeup water system, FW system, and vents and drains system, the systems that have AOVs in their program. The results of the evaluation show that the SPU does not affect the maximum differential pressures, flow rates, or fluid temperatures for the design-basis conditions for all of the systems except the FW system. Therefore, the SPU has no impact on the setup values for these AOVs, and the existing design pressure and temperatures are adequate for these valves. The shutoff head of the SG FW pump increases about 13 pounds per square inch (psi), which affects the AOV differential pressure analysis that is used to determine AOV minimum thrust/torque requirements for FW control valves (CPSES, Unit 1 and CPSES, Unit 2) and FW preheater bypass valves (CPSES, Unit 2 only) and FW split-flow bypass valves (CPSES, Unit 2 only). The licensee will update the differential pressure analyses for the AOVs in the FW system for the increase in system pressure, but the proposed SPU does not impact the IST Plan requirements for the FW system.

The licensee's review of affected systems indicates that the existing maximum operating conditions, i.e., flow rates, pressures and temperatures remain valid for the SPU. Therefore, there is no change in the pump head performance for the affected safety-related pumps at the SPU conditions. Therefore, pump designs and IST Program requirements for these pumps are not affected by the SPU.

In its submittal, the licensee described its review of the IST Program for safety-related pumps and valves at CPSES for SPU operations. The Code of Record for the first 10-year IST program at CPSES was the 1986 Edition of the ASME Code, Section XI for CPSES, Unit 1 and the 1989 Edition of the ASME Code, Section XI for CPSES, Unit 2. The IST Program at CPSES assesses the operational readiness of pumps and valves within the scope of the ASME Section XI Code. The scope of the IST Program at CPSES, and the testing frequencies, will not be affected by the SPU. The IST program must be periodically updated to meet applicable ASME OM Code requirements specified in 10 CFR 50.55a. However, in support of the SPU request, no effects are anticipated in the revised IST Program at CPSES.

2.2.4.3 Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps at CPSES in support of the SPU LAR. Based on the above described review, the staff has determined that the licensee adequately addressed the effects of the proposed SPU on safety-related pumps and valves. The NRC staff further concludes that the licensee has adequately evaluated the effects of the proposed SPU on its MOV programs related to GL 89-10, GL 96-05, and GL 95-07, and considered the lessons learned from those programs to other safety-related power-operated valves. Therefore, the NRC staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of GDC-1, GDC-37, GDC-40, GDC-43, GDC-46, and GDC-54, and 10 CFR 50.55a(f) following implementation of the proposed SPU at CPSES. As a result, the NRC staff finds the proposed SPU for CPSES to be acceptable with respect to safety-related valves and pumps.

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

2.2.5.1 Regulatory Evaluation

Mechanical and electrical equipment covered by this section includes equipment associated with systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal. Equipment associated with systems essential to preventing significant 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 SPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated pipe-whip and jet impingement forces. The primary input motions due to SSEs are not affected by an SPU. 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.

2.2.5.2 Technical Evaluation

At SPU conditions, the seismic design inputs remain unchanged. Therefore, the staff concurs with the licensee that the proposed SPU does not affect the seismic qualification of essential equipment.

The current structural design basis of CPSES implements the guidance of GDC-4 to include the application of LBB methodology, thus, eliminating consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping and 10-inch and larger RCL branch lines. The staff's review of the CPSES pipe-break evaluation for the SPU is contained in Section 2.2.1, where it is shown that no new pipe-break locations were identified for the SPU conditions and the jet impingement and pipe-whip restraints remain unaffected by the proposed SPU. Therefore, the staff concurs with the licensee that the SPU will have no adverse impact on essential equipment as a result of pipe whip, jet impingement and internal missiles.

2.2.5.3 Conclusion

The NRC staff has reviewed the licensee's evaluations of the effects of the proposed SPU on the qualification of mechanical and electrical equipment and concludes that the licensee has (1) adequately addressed the effects of the proposed SPU on this equipment and

(2) demonstrated that the equipment will continue to meet the requirements of GDC-1, GDC-2, GDC-4, GDC-14, and GDC-30; 10 CFR Part 100, Appendix A; and 10 CFR Part 50, Appendix B, following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the qualification of the mechanical and electrical equipment.

2.2.6 NSSS Design Transients

The effects of the SPU on the NSSS design transients have been evaluated and addressed in Sections 2.2.1 through 2.2.5, as appropriate.

2.2.7 Bottom-Mounted Instrumentation Guide and Flux Thimbles

The effects of the SPU on the in-core BMI system have been evaluated and addressed in Sections 2.1.5 and 2.2.2, as appropriate.

2.3 Electrical Engineering

2.3.1 Regulatory Evaluation

The regulatory requirements which the staff applied in its review of the SPU submittal include:

- GDC-17, “Electric power systems,” of 10 CFR 50, Appendix A requires that an onsite power system and an offsite electrical power system be provided with sufficient capacity and capability to permit functioning of SSCs important to safety.

- The regulation at 10 CFR 50.63 requires that all nuclear plants have the capability to withstand a loss of all AC [alternating current] power (SBO) for an established period of time, and to recover therefrom.

- The regulation at 10 CFR 50.49, “Environmental Qualification of Electric Equipment important to Safety for Nuclear Power Plants,” requires licensees to establish programs to qualify electric equipment important to safety.

2.3.2 Technical Evaluation

The staff reviewed the licensee evaluation of the impact of SPU on following electrical systems/components:

- AC Distribution System

- Power Block Equipment (Generator, Exciter, Transformers, Isolated-phase bus duct)

- Direct Current (DC) system

- Emergency Diesel Generators (EDGs)
- Switchyard
- Grid Stability
- Station Blackout (SBO)
- Equipment Qualification Program

2.3.2.1 AC Distribution System

In the SPULR, the licensee stated that the existing onsite AC distribution system remains adequate for the SPU conditions. The only impact is on the existing protection system relay settings for the non-Class 1E 6.6 kV rated RCP motors. The applied protective relaying schemes and setpoints for RCP hot- and cold-loop motor operation and RCP electrical penetrations are affected as a result of the increase of the brake horsepower of RCP motors to support unit operation at SPU conditions. The settings of the affected relays for the RCP hot- and cold-loop motor operation and RCP electrical penetration will be changed to address the increased current needed to support SPU conditions.

In response to staff's question, the licensee, in its letter dated April 17, 2008 (Reference 14), clarified that the CPSES RCP motor stators, both the originals and spares, are wound using a Class F insulation system. The stator windings are thermally rated at Class F but designed to operate at Class B temperature rise during hot-loop operation. The stator is designed not to exceed Class F temperature rise limit during cold-loop operation. The evaluation of the AC Distribution System addresses the specific items associated with the RCP motor load changes. The calculations for cable sizing and electrical equipment sizing were reviewed by the licensee and verified as adequate for higher RCP motor current. Some relay setting changes will be required as a result of motor load changes and will be implemented through the CPSES design modification process.

The licensee, in its letter dated January 10, 2008 (Reference 7), clarified that the adjustment of the protective system relay settings is part of the work scope identified and tracked as modifications within the CPSES Corrective Action Program (SMF-2006-003080).

NRC staff reviewed the licensee's assessment of the effects of the proposed SPU on the onsite AC distribution system and concludes that the licensee has adequately accounted for the effects of the proposed SPU on the system's functional design. The staff further concludes that the AC onsite distribution system will continue to meet the requirements of GDC-17 following implementation of the proposed SPU. Therefore, the staff finds the proposed SPU acceptable with respect to the AC onsite distribution system.

2.3.2.2 Power Block Equipment (Generator, Exciter, Transformers, Isolated-phase Bus Duct)

The existing rating of the main generator is 1350 MVA, 0.9 power factor. The new uprate main generator nameplate rating will be 1410 MVA at 0.9 power factor for each unit. According to the

SPULR, the main generator capability curve has been revised based on a Siemens generator uprate study.

The uprate of the main generator system will require enhancement of cooling system of the generator system. The cooling modifications are the replacement of the main generator hydrogen coolers, replacement of the isophase coolers and fans, and additional cooling for the exciter cooler.

The evaluation by the licensee showed that the continuous ampere ratings of the existing isolated-phase bus duct for the main generator and main transformer tap busses are inadequate to support unit operation at SPU conditions. The evaluation confirmed that isolated-phase bus duct main and tap bus short circuit design ratings envelop the available fault current levels for SPU conditions.

In response to the NRC staff's question, the licensee clarified in its letter dated January 10, 2008, that the isolated-phase bus cooling capacity was evaluated by the Original Equipment Manufacturer, Delta Unibus, for adequacy of the main generator and main transformer tap busses to support the unit's operation at SPU conditions. A modification to increase cooling requirements was recommended by the vendor. The modification to the isolated-phase bus cooling will replace the entire cooling package with an upgraded cooling package to support SPU. The upgraded cooling package will provide sufficient cooling for main generator and main transformer tap busses to support isolated-phase bus operation at SPU conditions. This modification will be implemented prior to power uprate of the respective unit.

In the SPULR, the licensee stated that its evaluation confirmed that the existing main transformers, with existing administrative limits, are adequate for the SPU.

In response to NRC staff's question, the licensee clarified in its letter dated January 10, 2008, that the existing CPSES main transformers have a nameplate rating of 650 MVA at 20.9 kV/345 kV. An additional cooler bank had been added to the main transformers several years ago to bring the equivalent thermal rating to 780 MVA.

Two main transformers are connected in parallel resulting in an equivalent rating of 1560 MVA. The transformer coolers have sufficient capacity to remove the heat load due to load losses with available margin for the new generator rating of 1410 MVA at 0.9 power factor.

CPSES maintains transformer primary-side voltage to 22.9 kV or less which limits transformer gassing to acceptable levels. This voltage level is about 4 percent above the generator nameplate of 22 kV and almost 10 percent above the transformer primary-side nameplate of 20.9 kV.

In response to the NRC staff's question, the licensee clarified in its letter dated January 10, 2008, that CPSES has decided to replace the main transformers to remove the voltage restriction and add additional margin. The new main transformers will be installed in the fall of 2009 on CPSES, Unit 2 and the spring of 2010 for CPSES, Unit 1.

In its letter dated February 21, 2008 (Reference 10), the licensee clarified that the change in transformer size will provide additional margin and flexibility to CPSES for meeting Electric

Reliability Council of Texas (ERCOT)/Oncor Electric Delivery needs. The changes that will be introduced by the replacement of the main transformers are small from the grid perspective. ERCOT and Oncor Electric Delivery believe that no adverse impacts will occur due to the small change. CPSES is required by ERCOT to provide the exact transformer impedances and other details to ERCOT prior to returning to power after the replacement of the transformers. CPSES has already provided transformer specification data to ERCOT/Oncor Electric Delivery and will provide per ERCOT requirements, on delivery of the transformers, the tested values for the transformers for inclusion in ERCOT/Oncor Electric Delivery models.

In response to another question from the NRC staff, the licensee stated in its letter dated April 17, 2008, that CPSES specified a transformer impedance value that would not increase the available short-circuit currents for the plant auxiliary systems. The final studies on short-circuit of the non-safety buses impacted by the transformer change will be completed through station procedures that implement the CPSES design modification process prior to the new transformer installation using actual transformer impedances.

Due to SPU increased generation capability, there will be an increase in current flowing through the CPSES, Units 1 and 2 main transformers and the tie-lines connecting the units to the switchyard. The existing protective system relay settings will be adjusted, as required, to reflect the increase in the load flow in the tie-lines connecting the CPSES, Units 1 and 2 main transformers to the switchyard. In the SPULR, it is also stated that evaluation of the main generator protection confirmed that the main generator total and partial loss of field and negative sequence relays settings are affected by the SPU conditions. The settings for these relays will be adjusted to support the SPU.

In response to the NRC staff's questions, the licensee, in its letter dated January 10, 2008, clarified that the adjustment of the protective system relay settings is part of the work scope identified and tracked as modifications within the CPSES Corrective Action Program (SMF-2006-003080).

The NRC staff reviewed the licensee's evaluation of the power block equipment for the impact of the SPU. The staff agrees that the proposed changes in the power block equipment, as discussed above, will be adequate to address the SPU conditions. The current main transformers will operate under voltage restrictions until the transformers are replaced.

2.3.2.3 DC System

The DC onsite power system includes the DC power sources and their distribution and auxiliary supporting systems that are provided to supply motive or control power to safety-related equipment.

In Section 2.3.4 of the SPULR, the licensee stated that the Class 1E and non-Class 1E portions of the DC power systems were evaluated to determine potential impacts of the SPU. No additional loads will be added to the DC systems and there will be no existing load changes as a result of the SPU. The capability and capacity of the DC system remains unchanged. DC load changes, resulting from plant modifications, are evaluated as part of the design change process. SBO and Fire Protection Program (FPP) evaluations did not result in any DC systems load changes.

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the DC onsite power system and concludes that the DC onsite power system will continue to meet the requirements of GDC-17 following implementation of the proposed SPU. Therefore, the staff finds the proposed SPU acceptable with respect to the DC onsite power system.

2.3.2.4 Emergency Diesel Generators

In the SPULR, the licensee stated that the evaluation of the EDG system and auxiliaries demonstrated that there are no changes to the EDG loading or run time as a result of SPU conditions. The EDG operation at SPU conditions remains bounded by the existing load analysis.

In response to the staff's question, the licensee, in its letter dated April 17, 2008, clarified as follows:

> The increased flow in auxiliary feedwater (AFW) system is related to the turbine driven AFW pump, not the motor driven AFW pumps. The loading on the motor driven AFW pump motors is not affected by the SPU. Therefore, this does not impact EDG loading. Also, the increase in decay heat associated with the power uprate has negligible effect on the required operating times for decay heat removal equipment in general and on AFW and residual heat removal (RHR) equipment in particular.

The licensee also clarified that the EDG fuel oil storage requirements are based on 7 days of continuous operation at rated load and hence are not affected by SPU. The EDG fuel oil consumption calculation and thus the fuel storage requirements are based on RG 1.137, Revision 1 and ANSI-N195 (1976), and are independent of any specific design-basis event scenario. EDG loading for these scenarios is below the full-rated load capability of the EDG.

The staff agrees with the licensee's assessment that there are no significant changes in the EDG system loads due to the SPU, and therefore, EDGs remain acceptable for SPU operation.

2.3.2.5 Switchyard

The main generator and transformer impedances are not affected by the SPU. Therefore, the fault contribution from CPSES units will not change. According to the SPULR, the short circuit levels remain acceptable for the CPSES switchyard equipment ratings. The 138 kV and 345 kV switchyard equipment ratings, including the tie-lines to the high-voltage bushings of the main transformers, startup transformer, and station service transformers, bound the SPU requirements.

The staff agrees that the analyses for switchyard reasonably bound the SPU conditions.

2.3.2.6 Grid Stability

In the SPULR, the licensee stated that ERCOT, through the Oncor transmission service provider evaluated the steady-state and stability studies for the impact of the SPU on the reliability of the CPSES 345 kV switchyard. The transmission service provider concluded that

the steady-state and dynamic performance of the CPSES at SPU remain essentially unchanged.

In response to the NRC staff's question, the licensee in its letter dated January 10, 2008, stated that the licensee requested ERCOT to perform the necessary studies to accept the uprated plant power output level changes of about 49 megawatts (MW) for CPSES, Unit 1 and 37 MW for CPSES, Unit 2. However, in a meeting held between ERCOT and TXU Electric Delivery on December 14, 2006, ERCOT stated that an additional steady-state study and a stability study would not be required for this small addition of 86 MW to the ERCOT grid.

ERCOT determined that a short circuit study would be required for SPU conditions. The results of the short circuit study, documented in the Circuit Breaker Interrupting Duty Study dated April 24, 2007, concluded that the available short circuit currents due to the proposed power uprate conditions will not exceed the rating of switchyard breakers.

In its letter dated February 21, 2008, the CPSES further clarified as follows:

> [CPSES] requires that Oncor Electric Delivery perform an annual review of the contingencies for voltage conditions that are stated in the [CPSES] Design Basis Document and [CPSES] agreements with Oncor Electric Delivery for availability of voltage at [CPSES] switchyards. Oncor Electric Delivery then submits a report to [CPSES] on the voltage conditions. The annual reports conclude that under the defined contingencies, [CPSES] switchyard voltage requirements are met.

According to ERCOT/Oncor Electric Delivery, there will be minimal change in the grid model as a result of the CPSES SPU. The corrected MW addition for CPSES, Unit 1 is 50.6 MW and for CPSES, Unit 2 is 38.6 MW, for a total of 89.2 MW. The corrected value is similar to the proposed 86 MW stated in the licensee's January 10, 2008, supplement. There will be an insignificant impact on the availability or reliability of the offsite power to CPSES as a result of this change.

The SPU data will be incorporated into the ERCOT/Oncor Electric Delivery model at the time the SPU occurs (fall 2008 for CPSES, Unit 1 and fall 2009 for CPSES, Unit 2). CPSES has requested that ERCOT/Oncor Electric Delivery include the SPU conditions in the August 2008 review report.

The staff agrees with the assessment of ERCOT/Oncor Electric Delivery that the change in the grid model will be minimal as a result of a small increase of MWe due to CPSES SPU. Therefore, the impact on grid stability and on the probability of loss of offsite power (LOOP) to CPSES will be insignificant.

2.3.2.7 Station Blackout

SBO refers to a complete loss of offsite and onsite AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the LOOP concurrent with a turbine trip and failure of the onsite emergency AC power system. SBO does not include the loss of available AC power to buses fed by station batteries through inverters or the loss of power from "alternate AC sources." The NRC staff's review focused on the impact of the

proposed SPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis.

The NRC requires that each nuclear power plant be able to cope for a specified period of time and recover from an SBO event per the SBO rule. CPSES was evaluated against the SBO Rule requirements using RG 1.155. The CPSES coping time is 4 hours.

The NRC staff review included the effect of the proposed uprate on the adequacy of the condensate and compressed air inventories necessary for the 4-hour coping time and the adequacy of AFW system flow for the uprated power level.

2.3.2.7.1 Condensate Inventory

The licensee determined that the required condensate inventory at the uprate licensed power level for decay heat removal and plant cooldown is bounded by the condensate inventory in TS 3.7.6. Thus, the condensate inventory is acceptable for operation at the uprated power level.

2.3.2.7.2 Compressed Air

The AOVs required to have accumulators to provide backup air supply upon loss of instrument air are the AFW flow control valves and the SG atmospheric relief valves (ARVs). The accumulators at each AFW control valve are sized on the basis of allowing the operator remote manual control to isolate a faulted SG for a period of 30 minutes after loss of air. Flow control is performed locally after the accumulator air is exhausted. Each SG ARV accumulator can provide for 15 positionings over a 4-hour period after loss of instrument air. All valves are accessible for local operation during SBO. The staff determined the compressed air supply remains acceptable for a 4-hour coping time at the uprated power level.

2.3.2.7.3 Auxiliary Feedwater Flow

The only parameter in the AFW flow rate analysis for current plant conditions affected by the SPU is the decay heat associated with the uprated core power level (increase from 3458 to 3612 MWt). The licensee determined that a flow rate sufficient for SPU conditions is within the capacity of the turbine-driven auxiliary feedwater pump (TDAFP). Therefore, the AFW system capacity is acceptable for operation at the uprated power level.

2.3.2.7.4 Class 1E Battery Capacity

Each Class 1E station battery for CPSES, Units 1 and 2 is designed to carry the connected loads continuously for a period of 4 hours in the event of a loss of onsite or offsite AC power. The station vital batteries are not affected by the SPU and continue to have sufficient capacity to meet SBO loads for the 4-hour coping duration at SPU conditions.

2.3.2.7.5 Effects of Loss of Ventilation

In response to the staff's RAI, the licensee in its letter dated April 17, 2008, clarified that the TDAFPs are located in rooms 1-074 in CPSES, Unit 1 and 2-074 in CPSES, Unit 2. Both

rooms 1-074 and 2-074, contain electrical equipment that is environmentally qualified. The areas contain the following types of components:

- Rosemont transmitters
- Fisher Electro Pneumatic Transducers
- NAMCO limit switches
- Limitorque motor actuators
- ITT Barton Pressure Switches

The environmental qualification (EQ) packages document that the components are qualified for temperatures in excess of 131.1 °F expected during an SBO event. The licensee further clarified that at TDAFPs, beyond the mechanical/hydraulic governor, there are no electrical safety-related components. The mechanical governor and governor valve are standalone components driven by steam pressure. There is a speed sensor on the turbine which sends speed indication to three locations - the control room (CR), the remote shutdown panel, and local in the TDAFP room. The speed sensor has no controlling function, hence no safety related function. Also, there is a manual/auto station on the main control board. It sends a 4-20 mA (milliampere) signal to a current-to-pneumatic (I/P) converter in the TDAFP room, which feeds into the mechanical governor. This control function is not required to be used during accidents. The turbine runs at a constant speed during an accident and flow is controlled with the flow control valve going to the SG.

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The staff concludes that the licensee has adequately evaluated the effects of the proposed SPU on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63 following implementation of the proposed SPU. Therefore, the staff finds the proposed SPU acceptable with respect to SBO.

2.3.2.8 Environmental Qualification of Electrical Equipment

EQ of electrical equipment involves demonstrating that the equipment is capable of performing its safety function under significant environmental stresses which could result from DBAs. The NRC staff's review focused on the effects of the proposed SPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, AOOs, and accidents. The staff's review was conducted to ensure that the electrical equipment will continue to be capable of performing its safety functions following implementation of the proposed SPU.

In Section 2.3.1 of the SPULR, the licensee stated that its EQ program ensures the continued qualification of safety-related electrical equipment that must function during and following design conditions postulated for DBAs and the post-accident duration. The constituent parts of the EQ program include the program basis, verification of equipment operability during and following exposure to plant environmental conditions, and proper installation and maintenance of equipment in the plant. These elements are controlled through a set of administrative documents consisting of a program description, implementing procedures, and reference documents.

Based on the NRC staff's RAI, the licensee, in its letter dated May 14, 2008 (Reference 15), provided the following supplemental information, regarding the EQ of electrical equipment:

> Safety Related Class 1E equipment and other equipment important to safety identified in the [CPSES] electrical equipment qualification program were screened to ensure that they would continue to meet the requirements of 10 CFR 50.49, operate satisfactorily, and continue to perform their intended safety functions at the power uprated conditions.
>
> The existing environmental parameters were compared to the post SPU conditions using the EQML [EQ Master List] in a spreadsheet format to screen for deviations in temperature, pressure and radiation. The review included normal and accident conditions both inside and outside containment. The review also addressed humidity and caustic spray.
>
> Normal pressure, temperature and humidity are unaffected by the SPU changes. There are also no changes to pH levels of the caustic spray. SPU does have an affect on the normal radiation doses.
>
> Harsh accident parameters are affected by SPU changes. Specifically, SPU does have an affect on the pressure and temperature LOCA profiles, and outside containment HELB [high-energy line break] profile and accident radiation doses.

The evaluation by the licensee found that the inside and outside containment equipment remains qualified for pressure, temperature and radiation conditions following a LOCA and HELB. Within the main steam penetration areas, the licensee stated that additional evaluations were required to address the reduced margins for the ASCO (American Switch Co.) solenoid valves, and NAMCO Quick connectors. Based on the staff RAI, the licensee in its letter dated May 14, 2008, provided the following detailed evaluations of the specific affected components:

> ASCO solenoid valves are qualified using two primary test reports AQS21678/TR and AQR-67368.
>
> The test report number AQS21678/TR [used for qualification of the solenoid valves with ethylene propylene diene monomer (EPDM) elastomer] did not attain the [IEEE 323-1974] recommended 15 °F margin on temperature. This condition is acceptable based on the following:
>
> (1) The test attained a temperature of 346 °F for three hours, while the requirement was 340 °F for 175 seconds [for SPU conditions based on HELB SPU profile].
>
> (2) The test included two transients to 346 °F each of which maintained 346 °F for 10,000 seconds.

(3) Test report number AQR67368 demonstrated a maximum temperature of 450 °F. This test included EPDM rubber and Viton elastomers [used in ASCO solenoid valves].

The ramp time of the required profile is steeper than the test profile. However, the peak temperature exceeded the required temperature by more than 110 °F. The required profile is bounded by the test profile. The required 15 °F margin is satisfied.

The NAMCO Quick Connectors are qualified to test report QTR-142.

The ramp time of test report number QTR-142 is longer than that of the required profile, and the test profile did not attain the [IEEE 323-1974] recommended 15 °F margin on temperature. This condition is acceptable based on the following:

(1) The tested profile was [based on] a two transient test. The first transient reached a peak temperature of 350 °F, while the second transient reached a peak temperature of 353 °F.

(2) Each of the two transients was maintained for 10,760 seconds.

(3) During the first 3 hour transient, the temperature did not drop below 344 °F, and during the second transient the temperature did not drop below 343 °F.

Margin is demonstrated by the time of peak temperature of the test specimens. The required peak temperature is 340 °F for 175 seconds. The test specimens were exposed to over 21,500 seconds at temperatures that exceeded 343 °F.

The licensee also performed location-specific environmental radiation calculations for the following five components since the SPU environmental radiation levels exceeded the previous SPU qualification levels of these components:

The five components are located inside containment and in the following locations:

- CPSES, Unit 1 pressure transmitter 1-PT-3616 – Room 154A
- CPSES, Unit 1 pressurizer vent valves, 1-HV-3609 and 1-HV-3610 – Room 161E
- CPSES, Unit 2 pressurizer vent valves, 2-HV-3609 and 2-HV-3610 – Room 161E

The location-specific calculations proved that the actual radiation levels are within the qualification level of the above components.

The staff reviewed the information provided by the licensee in the SPULR and the supplemental information. The NRC staff concludes that the licensee has adequately addressed the effects of the proposed SPU on the environmental conditions for the qualification of electrical equipment,

and the electrical equipment will continue to meet the relevant requirements of 10 CFR 50.49 following implementation of the proposed SPU.

2.3.3 Conclusion

Based on the technical evaluation provided in Section 2.3.2, the staff agrees that the SPU will continue to meet the requirements of applicable sections of 10 CFR 50, as discussed in Section 2.0. The SPU is considered acceptable.

2.4 Instrumentation and Controls

2.4.1 Regulatory Evaluation

Instrumentation and control (I&C) systems are provided (1) to control plant processes having a significant impact on plant safety, (2) to initiate the reactivity control system (including control rods), (3) to initiate the engineered safety features (ESF) systems and essential auxiliary supporting systems, and (4) 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 RTS, ESFAS, safe shutdown systems, control systems, and diverse I&C systems for the proposed SPU to ensure that the systems and any changes necessary for the proposed SPU are adequately designed such that the systems continue to meet their safety functions. 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 General Design Criteria (GDC) described in CPSES FSAR Sections GDC-1, GDC-4, GDC-13, GDC-19, GDC-20, GDC-21, GDC-22, GDC-23, and GDC-24. Specific review criteria are contained in CPSES FSAR Sections 7.1.1.1, 7.1.2, 7.2, 7.3, 7.4, 7.5, 7.6, 7.7, and 7.8.

2.4.2 Technical Evaluation

2.4.2.1 Suitability of Existing Instruments

For the proposed power uprate, the licensee evaluated each existing instrument of the affected NSSS and BOP systems 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 (SALs), the licensee verified that the acceptable safety margin continued to exist under all conditions of the power uprate. Where necessary, the licensee revised the setpoint and uncertainty calculations for the affected instruments. Apart from a few devices that needed change, the licensee's evaluations found most of the existing instrumentation acceptable for proposed SPU operation.

The licensee's evaluation resulted in the following changes at CPSES, Units 1 and 2.

Instrument Function	Change
Overtemperature N-16	Overtemperature N-16 trip setpoints constant values are revised as listed in Core Operating Limits Report (COLR).
Overpower N-16 trip setpoint	The nominal trip setpoint and allowable value for Overpower N-16 is being revised as listed in COLR.
Steam line low safety injection	Lead time constant for low-steam line safety-injection signal is reduced.
Rod control T_{avg} program	T_{avg} program modification based upon T_{avg} range from no-load to full-load (cycle-specific).
Pressurizer water level program	High limit changes if T_{avg} is greater than or equal to 574.2 °F and less than 584.7 °F (cycle-specific).
Steam dump control and turbine bypass	Plant trip controller setpoint are changed to accommodate the load rejection or reactor trip transient at SPU condition.
MS flow	Rebanding the main steam flow indicators required due to increase in FW/steam flow at SPU conditions.
Turbine first stage pressure	Rescale the instrumentation to accommodate the SPU conditions.
FW pump suction flow	Respan and recalibrate flow transmitters due to increased FW pump suction flows at SPU conditions.
Feedwater header pressure	Rebanding of control room FW header pressure indicators required due to increased pressure at SPU conditions.
SG FW pressure	Rebanding of control room SG FW pressure indicators required due to increased pressure at SPU conditions.
FW pump turbine speed control	Rescaling of FW pump speed control loop due to increase in main steam flow at SPU conditions in order to maintain flow control at less than or equal to 80% open.
FW pump suction pressure trip logic setpoints	Condensate polisher bypass setpoint is reduced by 40 psig [pounds per square inch gauge]. Low pressure heater bypass alarm and trip setpoint are each reduced by 40 psig. Staggered FW pump trip setpoints are reduced about 44 to 46 psig. New simultaneous dual pump trips have been added at 30 psig below staggered pump trips.
Manual turbine runback	New 50 MWe load reduction circuit added to turbine generator (TG) digital control system, allowing operator to reduce TG load manually when required.

These changes will be made to accommodate the revised process parameters. Based on the fact that these changes are based on the system review and analysis reviewed by the NRC staff and that the licensee will confirm the acceptability of these changes during power ascension testing, the staff agrees with the licensee's conclusion that when above modifications and changes are implemented, CPSES instrumentation and control system will accommodate the proposed SPU without compromising safety. None of the above changes affect the licensee's compliance with the existing plant licensing basis; therefore, CPSES continues to meet the current regulatory basis for the plant.

2.4.2.2 Instrument Setpoint Methodology

The licensee did not request any TS changes associated with instrument setpoint or allowable value in this amendment request. All the changes needed for the SPU either have been approved in a previous amendment or are in the process of approval. Therefore, the staff has

not reviewed the instrument setpoint methodology for CPSES in this SE and the staff's review of the instrument setpoint methodology is documented in the SE issued under Amendment No. 145 for CPSES, Units 1 and 2, "Changes to Technical Specifications to Reflect Cycle-Specific Safety Analysis Assumptions and Results of Adoption of Westinghouse Methodologies" (ADAMS Accession No. ML080580003).

2.4.3 Conclusion

The NRC staff has reviewed the licensee's application related to the effects of the proposed SPU on the functional design of the RTS, ESFAS, safe shutdown system, and control systems. The NRC staff concludes that the licensee has adequately addressed the effects of the proposed SPU on these systems and that the changes that are necessary to achieve the proposed SPU are consistent with the plant's design basis. The NRC 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 GDC-1, GDC-4, GDC-13, GDC-19, GDC-20, GDC-21, GDC-22, GDC-23, and GDC-24. Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to I&C.

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

2.5.1.1.1.1 Regulatory Evaluation

The NRC staff conducted a review in the area of flood protection to ensure that SSCs important to safety are protected from flooding. The NRC staff's review covered flooding of SSCs important to safety from internal sources, such as those caused by failures of tanks and vessels. The NRC staff's review focused on increases of fluid volumes in tanks and vessels assumed in flooding analyses to assess the impact of any additional fluid on the flooding protection that is provided. The NRC's acceptance criteria for flood protection are based on GDC-2. Specific review criteria are contained in SRP Section 3.4.1.

2.5.1.1.1.2 Technical Evaluation

For the proposed SPU, the NRC staff reviewed flood protection measures to ensure that SSCs important to safety are adequately protected from the consequences of internal flooding. The staff's review in this section evaluates internal flooding that the results from postulated failures of tanks and vessels. As described in Section 3.4.3 of the CPSES FSAR, the evaluation of internal flooding due to failures of non-seismic tanks and vessels was based on the instantaneous release of fluid from the tanks, and no modifications to the tanks and vessels was associated with the proposed SPU. Therefore, the SPU does not affect the protection from internal flooding resulting from postulated failures of non-seismic tanks and vessels.

2.5.1.1.1.3 Conclusion

The NRC staff has reviewed the proposed changes in fluid volumes in tanks and vessels for the proposed SPU. The NRC staff concludes that SSCs important to safety will continue to be protected from flooding and will continue to meet the requirements of GDC-2 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to flood protection.

2.5.1.1.2 Equipment and Floor Drains

2.5.1.1.2.1 Regulatory Evaluation

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 area for processing or disposal. The EFDS is designed to handle the volume of leakage expected, prevent a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment, and protect against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system. The NRC staff's review of the EFDS included the collection and disposal of liquid effluents outside containment.

The NRC staff's review focused on any changes in fluid volumes or pump capacities that are necessary for the proposed SPU and are not consistent with previous assumptions with respect to floor drainage considerations. The NRC's acceptance criteria for the EFDS are based on GDC-2 and GDC-4 insofar as they require the EFDS to be designed to withstand the effects of earthquakes and to be compatible with the environmental conditions (flooding) associated with normal operation, maintenance, testing, and postulated accidents (pipe failures and tank ruptures). Specific review criteria are contained in SRP Section 9.3.3.

2.5.1.1.2.2 Technical Evaluation

The function of the EFDS is to provide for the proper routing and control of leakage and to prevent the backflow of water/contaminated fluids to areas of the plant containing safety-related equipment. For conditions other than pipe breaks in certain systems (e.g., normal operational leakage and maintenance activities), the sources and design quantities of liquids that enter the equipment and floor drains will remain unchanged for the proposed SPU. The effects of high-energy pipe breaks are evaluated in Section 2.5.1.3, while the effects of other pipe breaks are discussed below. The existing backflow prevention capability remains acceptable because the proposed SPU results in no new areas containing safety-related equipment. Therefore, the proposed SPU does not affect the capability of the EFDS to perform its design functions.

2.5.1.1.2.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the EFDS and concludes that the licensee has adequately accounted for the plant changes resulting in increased water volumes and larger capacity pumps or piping systems. The NRC staff concludes that the EFDS has sufficient capacity to (1) handle the additional expected leakage resulting from the plant changes, (2) prevent the backflow of water to areas with safety-related equipment, and (3) ensure that contaminated fluids are not transferred to

noncontaminated drainage systems. Based on this, the NRC staff concludes that the EFDS will continue to meet the requirements of GDC-2 and GDC-4 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the EFDS.

2.5.1.1.3 Circulating Water System

2.5.1.1.3.1 Regulatory Evaluation

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems. The NRC staff's review of the CWS focused on changes in flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed SPU. The NRC's acceptance criteria for the CWS are based on GDC-4 for the effects of flooding of safety-related areas due to leakage from the CWS and the effects of malfunction or failure of a component or piping of the CWS on the functional performance capabilities of safety-related SSCs. Specific review criteria are contained in SRP Section 10.4.5.

2.5.1.1.3.2 Technical Evaluation

The CWS provides a continuous supply of cooling water to the main condenser to remove excess heat from the turbine cycle and auxiliary systems. For the proposed SPU, the NRC staff's review of the CWS includes evaluating the impact that the proposed SPU will have on existing flooding analyses due to any increases that may be necessary in fluid volumes or flow rates that could result from installation of larger capacity CWS pumps or piping. The CWS flow rate and operating pressures do not change at SPU conditions, and there are no modifications to the CWS resulting from the SPU. Accordingly, the analyses and design features related to internal flooding due to leakage or a break in the CWS for current plant conditions are unaffected by the SPU.

2.5.1.1.3.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the CWS and concludes that the licensee has adequately evaluated CWS for SPU conditions. The NRC staff concludes that, consistent with the requirements of GDC-4, the increased volumes of fluid leakage that could potentially result from the SPU would not result in the failure of safety-related SSCs following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the CWS.

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

2.5.1.2.1.1 Regulatory Evaluation

The NRC staff's review concerns missiles that could result from in-plant component overspeed failures and high-pressure system ruptures. The NRC staff's review of potential missile sources

covered pressurized components and systems, and high-speed rotating machinery. The NRC staff's review was conducted to ensure that safety-related SSCs are adequately protected from internally generated missiles. In addition, for cases where safety-related SSCs are located in areas containing non-safety-related SSCs, the NRC staff reviewed the non-safety-related SSCs to ensure that their failure will not preclude the intended safety function of the safety-related SSCs. The NRC staff's review focused on any increases in system pressures or component overspeed conditions that could result during plant operation, AOOs, or changes in existing system configurations such that missile barrier considerations could be affected. The NRC's acceptance criteria for the protection of SSCs important to safety against the effects of internally generated missiles that may result from equipment failures are based on GDC-4. Specific review criteria are contained in SRP Sections 3.5.1.1 and 3.5.1.2.

2.5.1.2.1.2 Technical Evaluation

The NRC staff's review of internally generated missiles is focused on missiles that could result from in-plant component overspeed conditions and ruptures of high-pressure systems. The review of postulated turbine-generated missiles is presented in Section 2.5.1.2.2. 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. The staff's review focuses on system modifications, increases in system pressures, and changes in the operating speed of components that are not bounded by existing analyses. The staff compared the SPU-related modifications against the internally generated missiles outside and inside containment identified in FSAR Tables 3.5-1 and 3.5-6, respectively, and found that: (1) there are no new components or changes to existing systems and components associated with the SPU that create the potential for new internally generated missiles, and (2) the SPU will not result in a significant increase in system pressures or in rotational energy for existing postulated missile-producing components that could result in the potential for additional or more severe internally generated missiles. Accordingly, the analyses and design features establishing that safety-related equipment is adequately protected from internal missiles are unaffected by the SPU.

2.5.1.2.1.3 Conclusion

The NRC staff has reviewed the changes in system pressures and configurations that are required for the proposed SPU and concludes that SSCs important to safety will continue to be protected from internally generated missiles and will continue to meet the requirements of GDC-4 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to internally generated missiles.

2.5.1.2.2 Turbine Generator

2.5.1.2.2.1 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 CPSES, Units 1 and 2 SPUs involve the replacement of the high-pressure turbine rotors and inner casing steam paths for each unit to accommodate the increase steam flows. The existing high-pressure turbine outer casing will remain unchanged. The NRC staff's

review of the TG sets focuses on the effects of the proposed SPU 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 SPU operation is judged based upon conformance with existing licensing basis considerations, as discussed in Section 3.5.1.3 of the CPSES, Units 1 and 2 FSAR.

2.5.1.2.2.2 Technical Evaluation

The CPSES missile analysis is based on a probabilistic method, in which the probability of turbine missile generation maintained below 1.0E-04 per year. This probability consists of two components: (1) the probability of turbine missile generation due to material degradation at normal operating speeds up to 120 percent of rated speed, and (2) the probability of turbine missile generation due to overspeed protection system failure resulting in speeds greater than 120 percent of rated speed.

The SPU modification to the high-pressure turbine increases the volume of steam and the energy contained within the turbine following actuation of the turbine overspeed protection system. This increase in entrapped energy increases the speed overshoot above the overspeed protection system setpoint. The SPU also increases the steam-mass flow rate through all turbines. The licensee reported that an evaluation of this overshoot for a complete load rejection from full SPU power indicated that the overshoot will increase from 8.4 percent to 9.0 percent above the 110 percent overspeed setpoint, resulting in an expected overspeed of approximately 119 percent. The predicted peak overspeed is less than the 120 percent design overspeed, thus, no increase in the probability of turbine missile generation is expected to result from the SPU modifications.

By letter dated May 22, 2007, the licensee requested a separate license amendment to increase the turbine control valve test interval, which does affect the probability of overspeed protection system failure. On February 29, 2008, the NRC issued the requested license amendment (ADAMS Accession Number ML080220107). However, because the SPU modifications do not affect the turbine overspeed protection system, the SPU modifications do not affect the probability of overspeed protection system failure resulting in destructive overspeed.

2.5.1.2.2.3 Conclusion

The NRC staff has reviewed the licensee's assessment of changes being made to the high-pressure turbine, steam mass flow rate, and other operational characteristics necessary to support the proposed SPU. The staff found that the effect of modifications associated with the SPU on the existing turbine overspeed protection are minor and that the turbine overspeed protection system will continue to protect the main turbine from excessive overspeed conditions following postulated transient and accident conditions, consistent with the existing licensing basis evaluation. Therefore, the proposed SPU is acceptable with respect to TG overspeed protection considerations.

2.5.1.3 Pipe Failures

2.5.1.3.1 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 SPUs is concerned with the impact that the proposed SPU 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 SPU and 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 as 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. 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 SPU operation is judged based upon conformance with existing licensing basis considerations as discussed primarily in Section 3.6B.1 of the CPSES, Units 1 and 2 FSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

2.5.1.3.2 Technical Evaluation

The licensee's evaluation of the impact that the SPU will have on the consequences of HELBs and moderate energy pipe cracks (MEPCs) that are postulated to occur outside containment is discussed in Section 2.5.1.3 of the SPULR. With the exception of the postulated MS and FW system operating parameters, the design temperatures and pressures remain within the values used for analyses of postulated pipe failures. In addition, the licensee's evaluation of SPU operating conditions identified no new or revised pipe-break locations, and the SPU modifications introduce no new equipment that must be protected from the effects of pipe breaks. Therefore, for systems other than main FW and MS systems, the pressure and temperature response for rooms and sub-compartments 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 SPU operation, and existing analyses of the extent of flooding resulting from postulated pipe failures will continue to be valid.

Operation at SPU conditions would change the MS system and main FW system operating conditions. The calculated mass and energy (M&E) releases for the limiting MS line pipe failure in the MS penetration areas results in small increase in temperature in the MS and FW penetration areas outside of containment. The impact on the qualification of equipment as a result of the HELB in the MS penetration areas is addressed in Section 2.3. The licensee stated that increases in the main FW system operating conditions could affect jet impingement and pipe-whip analyses. The effect of the FW system operating condition change on the dynamic effects of postulated pipe breaks is reviewed in Section 2.2. The licensee evaluated the effect

of flooding due to FW line failure and found that the existing acceptable flooding volume remained bounding for SPU operating conditions.

2.5.1.3.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU 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 SPU implementation. Therefore, the proposed SPU is considered to be acceptable with respect to high and moderate energy pipe failure considerations.

2.5.1.4 Fire Protection

2.5.1.4.1 Regulatory Evaluation

The purpose of the FPP is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary plant safe-shutdown functions nor will it 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 that they 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 the following: (1) 10 CFR 50.48, "Fire protection," insofar as they require the development of a FPP to ensure, among other things, the capability to safely shut down the plant; (2) GDC-3 of Appendix A to 10 CFR Part 50, 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 suppression systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; and (3) GDC-5 of Appendix A to 10 CFR Part 50, 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 Appendix D of NUREG-0800, Revision 5, SRP Section 9.5.1, as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of RS-001, "Review Standard for Extended Power Uprates." The CPSES, Units 1 and 2 FPP describes the fire protection features of the plant necessary to comply with Appendix A to BTP Auxiliary and Power Conversion Systems Branch 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants, Docketed Prior to July 1, 1976," as well as Sections G, J, and O of the Appendix R to 10 CFR Part 50. NUREG-0797, "Safety Evaluation Report Related to the Operation of Comanche Peak Steam Electric Station, Units 1 and 2," dated July 1981, and its Supplements through 24 for CPSES, Unit 1 and Supplements through 27 for CPSES, Unit 2, describe the approved FPP for CPSES Units 1 and 2. These SE reports are listed in the CPSES, Units 1 and 2 Operating License Condition 2.G.

2.5.1.4.2 Technical Evaluation

The licensee developed the SPULR utilizing the guidelines in RS-001. In the SPULR, the licensee evaluated the applicable SSCs and safety analyses at the proposed SPU core power level of 3612 MWt.

The staff's review of Section 2.5.1.4 of the SPULR indicated that the staff needed additional information to complete the review and requested the licensee to address the supplemental review criteria provided in Attachment 1 to Matrix 5 of RS-001. By letter dated January 10, 2008, the licensee provided the supplemental response. Based on the review of the original SPULR and the supplemental information, the staff was able to complete its review.

The licensee stated that the proposed SPU does not affect fire suppression and detection systems (except for when the fire protection system is utilized for purposes other than fire mitigation as discussed in this section later). No changes to fire barriers, fire protection responsibilities of plant personnel, nor procedures and resources (necessary for the repair of systems required to achieve and maintain cold shutdown) have been made as a result of the proposed SPU. Since no changes are being made to the FPP elements (administrative controls, fire suppression and detection systems, fire barriers, fire protection responsibilities of plant personnel, and procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown), the CPSES response to a fire shutdown scenario is not changed by the SPU. With consideration for increased decay heat, plant shutdown and cooldown can still be accomplished within the time requirements as stated in the CPSES Fire Protection Report. Therefore, there is no increase in the potential for a radiological release resulting from a fire.

The licensee also stated that the fire-safe-shutdown analysis and the plant cooldown analysis have been updated for SPU conditions. These analyses demonstrate that the plant can be shutdown and cooled to cold shutdown conditions well within the 72-hour requirement discussed in the CPSES Fire Protection Report. Since the ability to shut down and cooldown the plant at SPU conditions with increased decay heat loads is achieved within the required time limits, it is concluded that fuel design limits would not be exceeded and there would be no adverse consequences on the RPV integrity or the attached piping.

Hence, the licensee evaluated the effect on safe-shutdown by comparing the conditions for the proposed SPU with the current operating power level. The proposed SPU would not revise FPP elements and other operating conditions that may adversely impact the post-fire-safe shutdown capability. SPU 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 changes to the plant configuration or combustible loading as a result of modifications necessary to implement the SPU that affect the CPSES, Units 1 and 2 FPP. Also, the licensee updated the fire-safe shutdown and plant cooldown analyses due to increased decay heat load for the SPU conditions. The analysis results demonstrate that CPSES, Units 1 and 2 can be shut down and placed in cold shutdown following a fire within the 72 hours required by the CPSES, Units 1 and 2 Fire Protection Report. Further, the updated fire-safe shutdown analysis confirms that SPU does not impact RPV integrity or attached piping.

Section 2.5.1.4.2.2 of the SPULR, states that

> … time critical tasks are identified in the thermal/hydraulic analysis of the fire-safe shutdown scenario. Operations procedures implement the time critical tasks to:
>
> - Transfer power-operated relief valves (PORV) control to hot shutdown panel within five minutes
> - Establish seal return flow within 30 minutes
> - Start plant cooldown prior to two hours or pressurizer level exceeding 92 percent.

The staff requested that the licensee discuss any assumptions, especially those of a potentially non-conservative nature that may have been made in determining that the operator actions can confidently be accomplished within the available time. By letter dated January 10, 2008, the licensee confirmed that the time critical operator actions described above were identified previously in the fire-safe shutdown analysis for CPSES. These operator actions are not a result of the SPU. With the conditions of increased decay heat loads due to the SPU, these actions have not changed and are still acceptable for plant safe-shutdown in the event of a fire accident scenario. Assumptions of time response considered in performing these operator actions do not change as a result of the SPU.

Some of the plants credit aspects of their Fire Protection System (FPS) for other than fire protection activities, e.g., utilizing the fire water pumps and water supply as backup cooling or inventory for non-primary reactor systems. The staff requested the licensee to confirm if CPSES, Units 1 and 2 credit the FPS for such actions and provide details. By letter dated January 10, 2008, the licensee provided the following information.

The CPSES FSAR identifies two event scenarios for which the FPS is utilized for purposes other than fire mitigation.

Use of FPS to add inventory to the SFPs in the event SFP cooling and make-up from the reactor make-up water system are unavailable. Heat load in the SFPs has increased as a result of the SPU. The SFP heat load analysis at SPU conditions shows that the time to boil is still greater than 3 hours, which is consistent with the FSAR.

CPSES, Units 1 and 2 are required to assess the consequences of a crack in the break exclusion area of the MS line piping outside containment and inside a main steam isolation valve (MSIV) enclosure for equipment EQ only. The analysis assumes operation of the fire protection sprinkler system in the MSIV enclosure as a means to limit the environmental consequences (temperature and pressure) of the postulated crack in the break exclusion area of the MS line piping outside containment and and inside the MSIV closure. The impact of the SPU is an increase in the M&E release in the area. The licensee analyzed these scenarios and concluded that the existing sprinkler system provides acceptable cooling under SPU conditions.

Further, the licensee has credited the FPS as a mitigating methodology for large fires or explosions at the plant. The fire brigade mitigating actions for suppressing large fires and explosions is not impacted by the SPU.

2.5.1.4.3 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 due to the proposed SPU. The NRC 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 GDC-3 and GDC-5 following implementation of the proposed SPU. Therefore, the staff finds this aspect of the capability of the associated SSCs to perform their design-basis functions at SPU power level to be acceptable with respect to fire protection.

2.5.2 Pressurizer Relief Tank

2.5.2.1 Regulatory Evaluation

The pressurizer relief tank (PRT) is a pressure vessel provided to condense and cool the discharge from the pressurizer safety valves. The tank is designed with a capacity to absorb discharged fluid from the pressurizer relief valves (PRVs) 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 SPU. 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 HELBs 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 as 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 SPU operation is judged based upon conformance with existing licensing basis considerations as discussed primarily in Section 5.4.11 of the CPSES, Units 1 and 2 FSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

2.5.2.2 Technical Evaluation

The licensee's evaluation of the impact that the SPU 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 Section 2.5.2 of the SPULR. The CPSES FSAR states that the rupture discs on the PRT have a relief capacity equal to or greater than the combined capacity of the pressurizer safety valves. Since the capacity of the pressurizer safety valves is unchanged for SPU operation, the PRT remains adequately protected against failure due to overpressurization. The CPSES FSAR, through Amendment 101, states that the PRT is sized to receive and condense a discharge of 110 percent of the full-power pressurizer steam volume and that this steam volume requirement is approximately that which would be experienced if the plant were to suffer a complete loss of load (LOL) accompanied by a turbine trip but without the resulting reactor trip. In the SPULR, the licensee states that the PRT design is conservatively sized to condense and cool a steam discharge equal to 105 percent of the full-power pressurizer steam volume, which bounds the steam release from the loss of external electrical load transient analysis described in the SPULR. This change is a reduction in the design capacity of the PRT relative to the nominal full-power pressurizer steam volume. However, a complete LOL accompanied by a turbine trip without an immediate reactor trip is a very unlikely sequence of events and an unnecessarily conservative basis for the capacity of a non-safety-related component. The capacity to absorb the design steam release associated with a complete loss of electrical load satisfies the guidance of SRP Section 5.4.11, “Pressurizer Relief Tank,” and is acceptable.

2.5.2.3 Conclusion

The NRC staff has reviewed the licensee’s assessment of the effects of the proposed SPU 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 NRC staff guidelines. Therefore, the proposed SPU 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 SPU conditions. Consequently, the staff’s review focuses primarily on any adverse effects that the proposed SPU might have on the assumptions that were used in the analyses that were previously completed.

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 SPU 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

2.5.4.1.1 Regulatory Evaluation

The SFP 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 SPU operation in accordance with the SFPCCS licensing basis. The SFPCCS licensing basis, including design features, operating modes, cooling capabilities, pool temperature limits, and failure modes, is described in Section 9.1.3 of the CPSES FSAR.

2.5.4.1.2 Technical Evaluation

The licensee's evaluation of the impact that the SPU will have on the capability of the SFPCCS to continue to provide adequate cooling considering the additional heat load is provided in Section 2.5.4.1 of the SPULR. Although the SPU would result in a slight increase in the heat load, the licensee determined that the pool design temperature limits would not be exceeded. In the supplemental information provided by letter dated January 31, 2008, the licensee stated that the methodology and assumptions used in the analysis are unchanged. Thus, the increased heat load is accommodated by the existing margin of the cooling system.

2.5.4.1.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the capability of the SFPCCS to perform its safety function and finds that the SFPCCS will remain capable of maintaining the SFP below the maximum specified temperatures in accordance with licensing basis assumptions. Therefore, the proposed SPU is considered to be acceptable with respect to the SFPCCS.

2.5.4.2 Station Service Water System

2.5.4.2.1 Regulatory Evaluation

The service water system (SWS) provides essential cooling to the CCW system heat exchangers, the EDGs, the containment spray pump bearing oil coolers, and the safety injection and centrifugal charging pump lube oil coolers. The SWS also provides backup cooling water to

the AFW system. The NRC staff's review covered the functional performance of the SWS under the additional heat load that would result from the proposed SPU with respect to adverse operational conditions, abnormal operational conditions, and accident conditions (such as a LOCA with LOOP). 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 as a system should be provided with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions. The staff's review is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability for SPU operation is judged based upon conformance with existing licensing basis considerations as discussed primarily in Section 9.2.1 of the CPSES FSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

2.5.4.2.2 Technical Evaluation

The licensee's evaluation of the impact that the SPU 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 2.5.4.2 of the SPULR. The licensee determined that although SPU will result in a slight increase in the amount of heat that is rejected to the SWS, the system design limitations will not be exceeded.

The major potential contributors to the increased heat load due to SPU operation are the increased reactor decay heat at the SPU power level from the RHR heat exchangers and added decay heat loads from the spent fuel heat exchangers. The heat loads from the CCW heat exchangers to the SWS are controlled by limitations on the maximum allowable CCW heat exchanger outlet temperatures of 122 °F during normal cooldown and 135 °F during post-accident recirculation conditions. These limitations are unaffected by the SPU and effectively limit the heat transfer from the CCW heat exchangers to the SWS during the higher heat portions of each condition analyzed. The heat loads from the diesel generator jacket water cooler, the centrifugal charging pump lube oil cooler, the safety-injection pump lube oil cooler, and the containment spray pump bearing cooler remain unchanged at the SPU operating condition.

As a result of the SPU, there is a slight increase in the SFP cooling heat load applied to the SWS via CCW and ultimately to the safe shutdown impoundment (SSI). However, the licensee found the resultant higher SWS temperatures remain bounded by the current design temperature of the piping and valves. Also, existing programmatic controls established in response to GL 89-13 remain in place 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 the SPU 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.

2.5.4.2.3 Conclusion

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

2.5.4.3 Reactor Auxiliary Cooling Water Systems

2.5.4.3.1 Regulatory Evaluation

Reactor auxiliary cooling water systems circulate water to remove heat from plant components during plant operation, plant cooldown, and post-accident conditions. The reactor auxiliary cooling water system for the CPSES is the CCW system. The CCW system is a safety-related system designed to supply cooling water to components that are part of the RCS, ECCS, ESF systems, CVCS, SFPCCS, and waste processing system ventilation 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 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. 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 9.2.2 of the FSAR for the CPSES, except where proposed changes are found to be acceptable based upon the specified review criteria.

2.5.4.3.2 Technical Evaluation

The licensee's evaluation of the impact that SPU 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 2.5.4.3 of the SPULR. The licensee found that the reactor cooldown cases provide the greatest heat loads and are the limiting cases relative to CCW heat exchanger performance. The maximum CCW heat load during normal cooldown occurs when the RHR system is first placed in service, 4 hours after reactor shutdown. During cooldown using one train, with maximum cooldown heat load conditions present, the initial RHR heat load is throttled to limit CCW heat exchanger outlet temperature to a maximum temperature of 122 °F, which results in a longer cooldown time at SPU conditions. The licensee concluded that no changes would be required in the SWS or CCW system flow rates for SPU 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.

Section 9.2.2.3 of the CPSES FSAR describes that valves CC-0107, CC-0109, CC-0157, and CC-0158 have modified discs that have been drilled to serve as flow restriction orifices. These valves are closed to provide acceptable CCW flow balancing for DBAs to limit heat addition to the CCW system. The staff requested that the licensee describe how the heat addition to the CCW system at SPU DBA conditions has been evaluated to demonstrate that the CCW

temperature would be maintained at or below 135 °F during containment spray recirculation with an SWS temperature of 102 °F, consistent with the discussion in Section 2.5.4.3.2.3 of the SPULR. The staff also requested that the licensee clarify the basis for concluding the heat addition from normal shutdown cooling at a CCW temperature of 122 °F is more limiting than the post-accident condition. By letter dated January 31, 2008, the licensee explained that the effect of the SPU on post-LOCA heat removal via the CCW heat exchangers would be a change in heat removal via the RHR and containment spray system (CSS) heat exchangers during the recirculation phase of the event, only. The maximum allowable bulk temperature at the outlet of each CCW heat exchanger following a LOCA remains unchanged following SPU at 135 °F and the licensee completed an analysis to verify that the post-LOCA CCW heat exchanger outlet temperature did not exceed the system limit. The analysis assumed maximum RHR and CSS flow rates, minimum CCW system flow, including minimum CCW flow to the RHR and CSS heat exchangers, zero fouling of the RHR and CSS heat exchangers, as well as a conservatively high sump temperature. Thus, the analysis maximized CCW temperature, and the results of the analysis verified the CCW temperature limit would not be exceeded. The licensee clarified that the heat addition to the CCW system during shutdown cooling remains greater than the post-LOCA recirculation heat addition due to the much higher CCW flow rate through the RHR heat exchanger during shutdown cooling.

The licensee evaluated the original responses to GL 96-06, “Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions,” related to potential heatup and over-pressurization of CCW system piping and concluded the responses are not affected by SPU conditions since there are no physical changes or operational changes required by the SPU that would affect the containment penetration piping or isolation valves.

2.5.4.3.3 Conclusion

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

2.5.4.4 Ultimate Heat Sink

2.5.4.4.1 Regulatory Evaluation

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 CPSES UHS is the SSI, which is designed to dissipate heat rejected from the SWS. The SSI is designed to contain a water supply sufficient to allow simultaneous safe shutdown and cooldown of both units or safe shutdown of both units with one unit in LOCA allowing for a 30-day minimum reactor decay heat removal without outside makeup.

The NRC staff’s review focused on the impact of the proposed SPU on the decay heat removal capability of the UHS. Additionally, the review included evaluation of the design-basis UHS temperature limit to confirm that post-licensing meteorological data do not support more severe conditions than previously assumed. The acceptance criteria that are most applicable to the staff’s review of the UHS for proposed power uprates are based on GDC-44, insofar as the

capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions should be provided. The staff's review of the UHS 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 9.2.5 of the FSAR for the CPSES, except where proposed changes are found to be acceptable based upon the specified review criteria.

2.5.4.4.2 Technical Evaluation

The licensee's evaluation of the impact that SPU will have on the capability of the UHS to accept heat from the SWS during plant operation, plant cooldown, and post-accident conditions is provided in Section 2.5.4.4 of the SPULR. Acceptable performance of the heat sink is based on maintaining an acceptable inventory of water to accept the design-basis heat load at SPU conditions under limiting conditions.

The licensee used a three-dimensional hydrothermal model that was specifically developed for the SSI to predict its water temperature. As described in Sections 2.5.4.2 and 2.5.4.3 above, the rate of heat input to the SSI is controlled by design and procedural restrictions such that the rate of heat input increases only slightly at SPU conditions. Other input data, such as SWS flows, meteorological data, SSI initial temperature, and the SSI geometry, remain essentially unchanged from the previous analysis. The licensee stated that no changes were made to the models used to analyze the SSI for SPU conditions, and that examination of meteorological data for the period 1992 through 2006 determined that the limiting years for temperature and evaporation remain unchanged. Consequently, the licensing basis is unchanged with the exception of the increased heat load resulting from SPU.

The thermal analyses of the SSI performed at SPU conditions indicated that the peak SSI temperature for the LOCA scenario would increase slightly (i.e., increase by 0.2 °F to 115.9 °F) and that the final SSI level would decrease by 1 inch due to increased evaporation. The licensee concluded that these small changes would continue to provide adequate NPSH to the SSW pumps and adequate cooling of essential equipment.

2.5.4.4.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the UHS and finds that the licensee has adequately evaluated the impact of the proposed power uprate on the capability of the UHS system to perform its safety functions and that the UHS will remain capable of performing its licensing basis safety functions following SPU implementation. Therefore, the proposed SPU is acceptable with respect to the UHS.

2.5.4.5 Auxiliary Feedwater System

2.5.4.5.1 Regulatory Evaluation

In conjunction with a seismic Category I water source, the AFW system functions as an emergency system for the removal of heat from the primary system when the main FW system is not available. The AFW system also provides a cooling source in the event of a small-break loss-of-coolant accident (SBLOCA). Additionally, the system is used in the event of an MSLB, a

feedwater line break (FLB), a loss of power, or a low-low SG level condition. Under loss of all AC power (i.e., SBO), the turbine-driven AFW pump (TDAFP) remains capable of automatic or manual start to provide the decay heat removal necessary for coping with an SBO.

The AFW system consists of three separate pump trains. Two of the trains consist of individual and separate branches utilizing motor-driven AFW pumps (MDAFPs). One train consists of an individual and separate branch utilizing one TDAFP. Normally each MDAFP supplies two SGs, but the alignment can be altered to allow either MDAFP to supply any two or all four SGs. The TDAFP normally supplies FW to all four SGs. Each pump supplies the SGs through a normally open, motor-operated, discharge valve. The preferred source of water for the AFW system is the condensate storage tank (CST). A long-term source of water is available through a cross-tie with the SWS.

The NRC staff's review for SPUs focuses on the capability of the AFW system to provide sufficient emergency FW 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 SPU 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 10.4.9 of the CPSES FSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

2.5.4.5.2 Technical Evaluation

The licensee's evaluation of the impact that SPU will have on the capability of the AFW system to continue to provide an adequate supply of emergency FW to the SGs in the event normal FW is lost is provided in Section 2.5.4.5 of the SPULR.

With the assumptions that one MDAFP fails and all the flow from the second MDAFP is lost through a postulated FLB, the licensee determined that the minimum required flow from the TDAFP to the three intact SGs for an FLB accident increased from 400 gpm to 430 gpm at SPU conditions. The licensee concluded that the increased flow would require a change to the minimum operating point of the TDAFP and the IST acceptance criteria, but the increased flow was within the flow and head capacity margin of the pump. Otherwise, the SPU accident and transient analyses completed by the licensee demonstrate the existing AFW system arrangement and performance provide adequate flow at the necessary pressure to mitigate the consequences of the design-basis events and accidents, and support normal cooldown and safety-grade cold shutdown operations.

The NRC staff notes that the licensee has determined that a usable CST volume of 241,000 gallons is the minimum volume necessary to bring the unit from full uprated power to

hot standby conditions, maintain the unit at hot standby for 4 hours, and then cool down to RHR system entry conditions in 5 hours. The current TS useable volume is greater than the 241,000 gallons needed, and, therefore, no change to TS 3.7.6 is required for the uprate. Section 10.3.2.2 of the CPSES FSAR states that each ARV is sufficiently large to allow the plant to be cooled from no-load temperature to the RHR cut-in temperature of 350 °F prior to the time that the CST is exhausted. The licensee confirmed that the original sizing basis of the ARVs was greater than the sizing basis of the ARVs used for the SPU (i.e., 3612 MWt plus 0.6 percent uncertainty). Therefore, the capability to cooldown the plant consistent with the licensing basis is maintained for SPU operation.

2.5.4.5.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed SPU 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. The capacity requirements for the CPSES AFW system defined by revised accident analyses for SPU operation continue to be consistent with the existing system capabilities and the plant licensing basis. Therefore, the proposed SPU is considered to be acceptable with respect to the AFW system.

2.5.5 Balance-of-Plant Systems

2.5.5.1 Main Steam

2.5.5.1.1 Regulatory Evaluation

The MS system transports steam from the SGs to the power conversion system and various auxiliary steam loads. The portions of the MS system from the SGs up to and including the MSIVs, the ARVs, and the main steam safety valves (MSSVs) are designed as safety related. The MS supply to the AFW pump turbine and turbine exhaust piping is also safety-related. The MS system also provides a flow path for steam from the SGs to the steam dump system.

The NRC staff's review of the MS system for proposed power uprates evaluates system design limitations to assure that reactor safety will be preserved and protection of SSCs important to safety. This section of the SE focuses primarily on the capability of the MS system to provide a means to remove decay heat from the reactor. The acceptance criteria that are most applicable to the staff's review of the MS system for proposed power uprates are based on GDC-34, insofar as the capability to transfer fission product decay heat and other residual heat from the reactor core should be provided. The staff's review of the MS 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 of the CPSES FSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

2.5.5.1.2 Technical Evaluation

The licensee's evaluation of the impact that SPU will have on the capability of the MS system to remove residual heat from the reactor core under normal and accident conditions is provided in

Section 2.5.5.1 of the SPULR. Acceptable performance of the MS system is based on maintaining the capability to cool the reactor to RHR system entry conditions following operations at full SPU power.

The MS system provides a path to remove decay heat through the main steam ARVs and the steam dump system. The primary function of the ARVs is to provide a means for decay heat removal and plant cool down by discharging steam to the atmosphere when the condenser, the condenser circulating water pumps, or steam dump to the condenser are not available. Under such circumstances, the ARVs in conjunction with the AFW system permit the plant to be cooled down from the pressure setpoint of the lowest-set MSSVs to the point where the RHR system can be placed in service. The main steam ARVs are sized to have a minimum capacity of 62,150 pounds per hour (lb/hr at) 100 pounds per square inch absolute (psia) to support reactor cool down to RHR system operating conditions in 5 hours. This capacity is sufficient to achieve a cooldown rate of 50 °F per hour. This design basis is limiting with respect to the sizing of the ARVs and bounds the capacity required for an SG tube rupture event. The steam dump system is discussed in Section 2.5.5.3, Turbine Bypass.

2.5.5.1.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the ability of the MS system to remove adequate decay heat and found that the MS system will remain capable of performing its licensing basis safety functions following SPU implementation. Therefore, the proposed SPU is acceptable with respect to the MS system.

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). The NRC staff's review of the main condenser for proposed power uprates focuses primarily on the impact that a SPU will have on the control of radiological releases to the environment. For PWRs, the effect of the proposed SPU is negligible because leakage from the RCS through the SG to the MS system is limited. Therefore, an evaluation of the main condenser in this section is not required.

2.5.5.3 Turbine Bypass

The TBS at CPSES is known as the steam dump system, and it 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 Westinghouse original sizing criterion conservatively recommended that the steam dump system (valves and pipe) be capable of discharging 40 percent of the rated steam flow at full-load steam pressure to permit the plant to withstand an external load reduction of up to 50 percent of plant-rated electrical load without a reactor/turbine trip. To prevent a trip, this transient requires all reactor control systems to be in automatic, including the rod control system, which accommodates 10 percent of the load reduction. The steam dump system prevents MSSV lifting following a reactor trip from full power. Each CPSES unit is equipped with 12 condenser steam dump valves. Each valve is currently sized to have a flow capacity of about 845,292 pounds mass per hour (lbm/hr) at a valve inlet pressure of 930 psia. This valve capacity provides a total steam dump system

capacity that exceeds the original Westinghouse sizing criterion. This capacity exceeds that necessary for prompt cooldown to RHR system operation entry conditions. Because no changes are 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

2.5.5.4.1 Regulatory Evaluation

The condensate and feedwater system (CFS) provides FW 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 FW piping from the SGs up to and including the outermost containment isolation valves and the valves providing FW isolation capability. 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 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. 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 SPU 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 10.4.7 of the CPSES FSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

2.5.5.4.2 Technical Evaluation

The licensee's evaluation of the impact that the SPU will have on the CFS's ability to provide FW to the SGs is provided in Section 2.5.5.4 of the SPULR. During SPU operation, FW 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 will have sufficient margin to satisfy flow requirements for the uprated plant. However, the licensee found that the heater drain pump impellers would have to be modified in order to maintain appropriate heater drain tank level control. The licensee concluded that, with the requisite setpoint changes and the heater drain pump modification, the CFS will be fully capable of satisfying the FW flow requirements for SPU operation.

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

2.5.5.4.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the CFS and finds that the CFS will remain capable of providing FW to the SGs without creating

unacceptable fluid flow instabilities and increased challenges to reactor safety systems. Because the condensate and FW pumps have sufficient margin to accommodate the increased FW flow requirements for SPU operation, required CFS modifications are minor (involving mainly setpoint changes and the heater drain pump impeller modification). Since system design specifications will not be exceeded due to SPU operation, the staff finds that the reliability and stability of the CFS should not be adversely affected by SPU operating conditions. Furthermore, any problems related to CFS performance will be readily apparent during SPU power ascension. Therefore, the CFS will continue to satisfy licensing basis considerations and the proposed SPU is considered to be acceptable with respect to the CFS.

2.5.6 Waste Management Systems

2.5.6.1 Gaseous Waste Management Systems

2.5.6.1.1 Regulatory Evaluation

Gaseous waste management systems (GWMSs) involve the gaseous radwaste system, which deals with the management of radioactive gases collected in the off gas 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 SPU 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) 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) 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 guidelines for meeting the "as low as is reasonably achievable," ALARA, 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 11.3 of the CPSES FSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

2.5.6.1.2 Technical Evaluation

The licensee's evaluation of the impact that SPU will have on the capability of the GWMS to collect and process gaseous radioactive waste, is provided in Sections 2.5.6.1 of the SPULR. The licensee determined that the SPU 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 radioactive waste system. The licensee found that the existing GWMS will remain capable of processing this increase in radioactive nuclide concentration. SPU activities

do not add any new components to the GWMS, nor do they introduce any new functions for existing components.

Radiological and environmental monitoring of the waste streams is not affected by the proposed SPU and no new or different radiological release paths will be introduced. However, the proposed SPU will result in an increase in the activity associated with gaseous radioactive waste and, therefore, potential radiological releases and offsite doses will be impacted. The releases related to the acceptance criteria of 10 CFR 20.1302 and Appendix I to 10 CFR Part 50 and radiological exposures related to the acceptance criteria of GDC-61 under normal operating conditions are addressed in the Environmental Assessment and Finding of No Significant Impact for the Proposed SPU referenced in Section 7.0 of this SE. Potential accidental releases are evaluated in Section 2.9 of this SE.

Section 11.3.2.1.1. of the CPSES FSAR states that a catalytic recombiner is used to combine hydrogen brought into the GWMS with a controlled amount of oxygen to form water. The control system for the recombiner maintains an oxygen lean mixture to preclude the possibility of a hydrogen explosion and monitors both the hydrogen and oxygen amounts to preclude creation of potentially explosive gas mixtures in the GWMS. Thus, the control of potentially explosive gas mixtures within the GWMS is unaffected by operation at SPU.

2.5.6.1.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the capability of the GWMS to perform its functions and finds that the GWMS will continue to control the release of radioactive materials through collection of radioactive gases 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 acceptance criteria of GDC-60. Consequently, the proposed SPU is considered to be acceptable with respect to the GWMS.

2.5.6.2 Liquid Waste Management Systems

2.5.6.2.1 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 components 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 SPU 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 ALARA 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 of the CPSES FSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

2.5.6.2.2 Technical Evaluation

The licensee's evaluation of the impact that the SPU will have on the capability of the LWMS to collect and process liquid radioactive waste is provided in Section 2.5.6.2 of the SPULR. The licensee determined that the proposed SPU 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 SPU. Since the design and operation of the LWMS will not change, and the design volume of fluid flowing into the liquid radwaste system will not change as a result of SPU, the licensee concluded that the capacity of the LWMS will continue to be adequate.

The licensee evaluated the impact of the proposed SPU on the LWMS using the methodology outlined in NUREG-0017, Revision 0, to estimate the change in coolant and steam activity due to the SPU. 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 SPU will have on radioactive waste liquid effluents and projected doses. The licensee found that the SPU will result in an increase of approximately 6.5 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. The licensee's evaluations of potential releases related to the acceptance criteria of 10 CFR 20.1302 and Appendix I to 10 CFR Part 50 are addressed in the Environmental Assessment and Finding of No Significant Impact for the Proposed SPU referenced in Section 7.0 of this SE.

2.5.6.2.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU 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. Because the collection and confinement of the liquid radioactive waste is unchanged by the SPU, the acceptance criteria related to GDC-60 and GDC-61 continue to be satisfied. Therefore, the proposed SPU 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 SPU

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 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. The calculated EDG fuel oil consumption remains bounding at the SPU condition because there are no changes in the loading or duration of operation of equipment for the SPU. Therefore, the fuel oil storage requirements for the CPSES are not affected by the proposed SPU and 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-SPU fuel is mechanically the same as the pre-SPU fuel, this area of review is not affected by the proposed SPU and an evaluation of the LLHS is not required.

2.5.8 Additional Review Areas (Plant Systems)

There are no additional plant system review areas requiring the evaluation for the proposed SPU.

2.6 Containment Review Considerations

2.6.1 Primary Containment Functional Design

While operating at SPU condition, and following a DBLOCA or an MSLB accident, the peak pressure and temperature within the containment must remain below the containment's internal design pressure and design temperature. The containment structure is designed to withstand internal pressurization from high-energy pipe breaks within it and the external pressurization due to inadvertent actuation of the CHR systems. The containment internal design pressure is 50 psig, and the design temperature is 280 ^{o}F.

2.6.1.1 Regulatory Evaluation

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 CHR 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 Sections 6.2.1.1.A and 6.2.2.

2.6.1.2 Technical Evaluation

The licensee used the GOTHIC computer code version 7.2a methodology for LOCA and MSLB accident containment performance analyses. The licensee states that the GOTHIC containment modeling for CPSES is consistent with the recent NRC-approved Ginna evaluation model (Reference 18). The latest code version is used to take advantage of the diffusion layer model (DLM) heat transfer option. The licensee further states that this heat transfer option was approved by the NRC for use in Ginna containment analyses with the condition that mist be excluded from what was earlier termed as mist diffusion layer model (MDLM). The GOTHIC containment modeling for CPSES has followed the conditions of acceptance placed on Ginna.

The licensee was asked to verify that all input parameters to the containment peak pressure and temperature analyses (e.g., containment volume, heat sink descriptions, heat exchanger performance, equipment flow rates and flow temperatures, initial relative humidity, UHS temperature) remain the same as those in the FSAR except for those affected by the SPU. In a letter dated January 31, 2008 (Reference 9), the licensee states that the same standard Westinghouse LOCA M&E release methodology from WCAP-10325-P-A (Reference 19) was used to calculate the long-term double-ended pump suction (DEPS) and the double-ended hot-leg (DEHL) break releases for the SPU. The licensee further states that the GOTHIC containment model for the CPSES, Units 1 and 2 was built in accordance with Westinghouse analysis methods and NRC guidelines and limitations for the use of the DLM model which is a change from the usage of Uchida/Tagami heat transfer correlations in CONTEMPT. The heat sink surface areas, thickness, material properties, and paint coatings are same as the current design analyses of record with the CONTEMPT code. The spray flow rates and actuation setpoints are the same as the current design analyses of record with the CONTEMPT code as was the RHR heat exchanger performance. All of the SPU cases with GOTHIC were performed with the highest allowable TS containment operating pressure of 16.2 psia as the initial containment pressure along with a low relative humidity of 15 percent. This differs from the sensitivity cases with CONTEMPT that used containment pressure of 14.2 psia, 14.7 psia, and 16.2 psia with an initial relative humidity of 100 percent because the sensitivities to flashing in GOTHIC differ from CONTEMPT when addressing maximum peak calculated containment pressure. The spray delay times used in GOTHIC SPU cases correspond to the longest delay time for a LOOP in order to bound cases where offsite power (LOOP) could be available.

The SPULR Section 2.6.1.2.2 states that in changing from the CONTEMPT code to the GOTHIC code, the known difference that exists between the current licensing analysis and the SPU containment integrity analysis is the treatment of the containment spray flow. The efficiency of the CSS is modeled in GOTHIC as 84.2 percent during the injection phase and

recirculation phase. The licensee states that the remaining spray flow is not credited for heat removal from containment atmosphere, containment structures, or the containment sump. The licensee further states that in the current licensing basis analysis, 15.8 percent of the spray flow does not cool the atmosphere or the heat sinks but it does contribute to cooling of the liquid in the sump. In an NRC staff RAI, the licensee was asked to explain why the same spray efficiency is used for both injection and recirculation phases of the LOCA when the spray water temperature is much higher during the recirculation phase. In addition, the licensee was asked to explain why spray efficiency is used rather than allowing GOTHIC to calculate the heat and mass transfer to the spray drops. In its response dated January 31, 2008 (Reference 9), the licensee states that the system "efficiency" of 84.2 percent was developed to account for blocked spray nozzles and pump degradation and the same "efficiency" exists during the injection phase and the recirculation phase but the flow rates that were input to GOTHIC during these phases are different. The containment spray efficiency that is described in the SPULR Section 2.6.1.2.3 and Table 2.6.1-1 is combined with the design flow rate to arrive at the equivalent spray system flow rate during the injection phase and the recirculation that is input to GOTHIC. The licensee further states that the "efficiency" is essentially a degraded analysis value for the assumed spray flow rate and that GOTHIC calculated the heat and mass transfer to the spray droplets.

2.6.1.2.1 LOCA Short-Term Containment Response

The licensee's results for the short-term containment response show that the peak pressure occurs near the end of the initial blowdown and, therefore, its magnitude is independent of the ECCS or CHR system, because these systems come into operation after the peak pressure occurs. The highest peak pressure was 40.83 psig occurring at 22 seconds from the beginning of blowdown for a DEHL break. The highest peak temperature was 260.5 ^{o}F occurring at 21.5 seconds from the beginning of blowdown for a DEHL break. The staff accepts LOCA short-term containment response analysis because the licensee determined that the peak pressure and temperature are less than the containment design pressure and temperature of 50 psig and 280 ^{o}F respectively.

2.6.1.2.2 LOCA Long-Term Containment Response

The licensee determined that the accident which produces the maximum energy release during the post-blowdown period is a DEPS break. The initial conditions of maximum pressure, maximum temperature and minimum relative humidity along with a single failure of loss of an EDG produces the slowest containment depressurization for this break. The single failure of the EDG results in one train of the ECCS and containment safeguards equipment being unavailable. The CHR systems that are assumed available are one RHR heat exchanger, one CCW heat exchanger, and one containment spray train. Further, LOOP delays the actuation times of the safeguards equipment due to the time required for diesel startup after receipt of the safety-injection signal.

The analysis shows that the containment peak temperature of 266.1 ^{o}F occurs at 446.6 seconds and the ultimate peak pressure of 44.45 psig is reached at 3407 seconds. The current licensing containment response basis results for containment peak pressure and temperature for the LOCA event is 44.9 psig and 272.1 °F, respectively. The results show that all cases are below the containment design conditions of 50 psig and 280 °F. The results also show that peak

pressure and temperature at 24 hours is 9.86 psig and 172.6 °F, respectively. The long-term DEPS break case is well below 50 percent of the peak containment pressure value within 24 hours.

2.6.1.2.3 Main Steam Line Break Containment Response

The licensee states that the containment initial conditions that result in maximum peak containment pressure are maximum initial pressure and temperature and minimum initial relative humidity. The licensee calculated a peak containment pressure of 39 psig which occurs for a 4.7 square foot split break at 30 percent initial power with a failure of a train of containment safeguards and the main feedwater isolation valve (MFIV) in the faulted loop. The peak pressure occurs at 620 seconds from the time of the break.

The licensee states that the containment initial conditions that result in maximum peak containment temperature are minimum initial pressure and relative humidity and maximum initial temperature. The licensee calculated a peak containment vapor temperature of 324.9 °F for a 4.3 square foot split break at 100.6 percent initial power with failure of MSIV and MFIV in the faulted loop to close. The peak temperature occurs at 40 seconds from the time of the break, and is less than the peak containment vapor temperature of 343.5 °F given in the current licensing basis FSAR Figure 6.2.1-15. Consequently, the maximum containment liner temperature under SPU condition is bounded by the liner temperature in the current licensing basis.

2.6.1.3 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 M&E that would result from the proposed SPU. 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 GDC-13, GDC-16, GDC-38, GDC-50, and GDC-64 following implementation of the proposed SPU. Therefore, the staff finds the proposed SPU acceptable with respect to containment functional design.

2.6.2 Subcompartment Analyses

2.6.2.1 Regulatory Evaluation

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

2.6.2.2 Technical Evaluation

The LBB methodology has been applied to CPSES, Units 1 and 2 to exclude from the design basis the dynamic effects of postulated pipe ruptures in the primary coolant piping and 10-inch and larger RCL branch lines. The NRC has approved this methodology for CPSES in Supplemental Safety Evaluation Reports (SSERs) 23 and 26. As stated in SPULR Section 2.1.6, the licensee performed plant-specific LBB analysis for CPSES, Units 1 and 2 to show that the LBB acceptance criteria in regards to leak rate, flaw size, and loads continue to be satisfied for primary loop piping, pressurizer surge line, RHR piping, accumulator injection nozzles, and the accumulator injection lines at the SPU conditions. The SPU analyses were performed using the current licensing basis methodology documented in FSAR Section 6.2.1.2, Containment Subcompartments.

As stated in the SPULR Section 2.6.2.2, the licensee eliminated several line breaks in subcompartments from further evaluation as the current M&E releases utilized for CPSES, Units 1 and 2 remain unchanged for the SPU since the no load (zero percent power) case is the limiting condition. Consequently, no further evaluation was required for steam line and auxiliary FLB within SG cubicle, and MSLB within the main steam penetration area. The licensee also eliminated the FLB within the SG compartment from further evaluation because the SPU M&E releases for CPSES, Units 1 and 2 are the same as in the current licensing basis due to an insignificant difference in the FW operating conditions. The staff agrees that this is acceptable.

The licensee states that for the RHR system line break within the SG compartment, the CPSES, Unit 2 SPU mass release increased by approximately 2.5 percent from its current licensing basis. The licensee evaluated its impact and confirmed by analysis that the SG compartments continue to maintain their structural integrity under the SPU conditions.

The licensee states that for the FLB within the FW penetration area, the CPSES, Unit 1 SPU M&E release is same as the M&E released in the current licensing basis because the FW operating conditions are not significantly different. For CPSES, Unit 2, the licensee determined that the FW operating conditions are more limiting than the conditions in the current licensing basis. The licensee evaluated its impact and confirmed by analysis that the FW penetration area maintains its structural integrity under the SPU conditions.

For a spray line break within the pressurizer cubicle, the licensee determined that the short-term SPU M&E releases are greater but are within the 10 percent margin included in the current evaluations for both units. Due to CPSES, Unit 1 SG replacement, the licensee determined that at least 1 percent of that margin remains available for this unit. The licensee states that the Unit 1 current pressurizer cubicle spray line break M&E releases remain bounding with 1 percent margin over the SPU conditions based on the consideration that the SPU RCS temperatures and the associated plant-specific instrument uncertainties are slightly less limiting

than the conditions utilized for its SG replacement. Based on the above justification, the licensee states that no further evaluations of the spray line break within the pressurizer cubicle is required for both units.

For the CVCS, the licensee states that the SPU system operating conditions are less limiting than the current operating conditions. For a CVCS line break within the excess letdown heat exchanger cubicle, SPU M&E releases for both units remain bounded by the current M&E releases and, therefore, no further evaluation is required.

For the CSS, the licensee states that the SPU system operating conditions are less limiting than the current operating conditions. For a containment spray line break within the regenerative heat exchanger cubicle, SPU M&E releases for both units remains bounded by the current M&E releases and therefore no further evaluation is required.

2.6.2.3 Conclusion

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased M&E release. The NRC 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 differences across the walls following implementation of the proposed SPU. Based on this, the NRC staff concludes that the plant will continue to meet GDC-4 and GDC-50 for the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to subcompartment analyses.

2.6.3 Mass and Energy Release Analyses

2.6.3.1 Mass and Energy Release Analysis for LOCA

2.6.3.1.1 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 M&E release rate calculations for the initial blowdown phase of the accident. The NRC's acceptance criteria for M&E release analyses for postulated LOCAs are based on (1) GDC-50, insofar as it requires that sufficient conservatism be provided in the M&E 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.

2.6.3.1.2 Technical Evaluation

The licensee performed the SPU LOCA M&E releases using NRC-approved Westinghouse models (References 19, 20, and 21). The model comprises M&E release versions of the codes SATAN VI for blowdown phase; WREFLOOD for the period of time when the lower plenum is being filled with by the accumulator and ECCS water and continues when water from the lower plenum enters the core and ends when the core is completely quenched; FROTH for the

post-reflood portion of the transient until the time that the secondary side of the intact loop SGs are depressurized to the containment design pressure; and EPITOME which continues the FROTH post-reflood portion of the transient to 3600 seconds. The long-term post-3600 second, M&E release calculations are performed through user-defined functions by GOTHIC. These input functions are used to incorporate the sump water cooling in the long term and are consistent with the Westinghouse GOTHIC methodology approved by the NRC.

For containment subcompartment analyses, the licensee used the current licensing basis short-term LOCA M&E release analysis methodology documented in FSAR Section 6.2.1.2. The short-term M&E releases depend on the critical mass flux which increases with an increase in pressure and a decrease in temperature. The licensee states that the short-term blowdown transients are characterized by a peak M&E release rate that occurs during a subcooled condition; thus, the Zaloudek correlation, which models this condition, is presently used in the short-term LOCA M&E release analyses (Reference 21). The licensee used this correlation to conservatively evaluate the SPU impact on the deviations in the RCS temperatures. The licensee used a lower RCS temperature to maximize the short-term LOCA M&E releases.

As per FSAR Section 6.2.1.2, CPSES, Units 1 and 2 have been licensed in accordance with the 1987 revision of GDC-4; therefore, the dynamic effects of RCS main loop piping breaks, and RCS branch line breaks 10-inch diameter and larger were eliminated from consideration. The breaks that were considered are the largest branch line off of the primary loop piping. These branch lines include the pressurizer spray line and the RHR line from the hot leg to the first isolation valve.

Short-term SPU LOCA M&E release evaluations for containment subcompartments, are addressed in Section 2.6.2 of this report.

2.6.3.1.3 Conclusion

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

2.6.3.2 Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures

2.6.3.2.1 Regulatory Evaluation

The NRC staff's review covered the energy sources that are available for release to the containment, the M&E release rate calculations, and the single-failure analyses performed for steam and FW line isolation provisions, which would limit the flow of steam or FW to the assumed pipe rupture. The NRC's acceptance criteria for M&E 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.

2.6.3.2.2 Technical Evaluation

The licensee states that the SPU MSLB M&E release evaluation demonstrated that the CPSES, Unit 1 containment analysis results bound those for Unit 2 analysis. Therefore, the results of Unit 1 analysis are presented for NRC staff review at the SPU condition. In the analysis, the licensee used conservative assumptions for both the primary and secondary side, and also for the protection system actuation in order to maximize the M&E releases in the containment through the secondary-side break. The basis of these assumptions is as per NRC-approved Westinghouse report (Reference 22). This report uses the MARVEL as the M&E release analysis code. However, for the current licensing basis analysis, the licensee used the LOFTRAN code, and for SPU analysis used the RETRAN code documented in Westinghouse report WCAP-14882-P-A (Reference 23). The licensee adhered to all limitations in using the RETRAN code which are documented in the NRC SE report for WCAP-14882-P-A. These limitations are (a) the break flow model is Moody critical flow model referenced in SRP 6.2.1.4, (b) dry steam exits from the break assuming a perfect separation in the SG, and (c) any superheated steam conditions will be reset to be equal to the saturation temperature. The licensee performed the analysis for initial power levels of 100.6, 70, 30, and zero percent of the uprated power, based on the information in WCAP-8822. The assumptions used for postulated single-failure are also based on information in WCAP-8822. The evaluation of licensee's analysis results is provided in Section 2.6.1 of this report under the heading "Main Steam Line Break Containment Response." The NRC staff considers licensee's evaluation acceptable.

2.6.3.2.3 Conclusion

The NRC staff has reviewed the M&E release assessment performed by the licensee for postulated secondary system pipe ruptures and finds that the licensee has adequately addressed the effects of the proposed SPU. Based on this, the staff concludes that the analysis meets the requirements in GDC-50 for ensuring that the analysis is conservative. Therefore, the staff finds the proposed SPU acceptable with respect to M&E release for postulated secondary system pipe ruptures.

2.6.4 Combustible Gas Control in Containment

2.6.4.1 Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excessive hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The 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 NRC staff's review primarily focused on any impact that the proposed SPU 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.

2.6.4.2 Technical Evaluation

In September 2003, the NRC amended 10 CFR 50.44 to eliminate certain requirements for hydrogen recombiners and hydrogen purge systems and relaxed the requirements for hydrogen and oxygen monitoring equipment to make them commensurate with risk significance. Based on the rule change, the licensee submitted a LAR by letter dated October 28, 2004 (Reference 24), requesting removal of the electrical hydrogen recombiners from the TSs. The NRC staff approved the LAR by letter dated April 21, 2005 (Reference 25), which removed hydrogen recombiners from the TS, and reclassified the monitoring system from safety-related to non-safety-related consistent with RG 1.97. The licensee will maintain the hydrogen monitoring system as described in the FSAR. This will not be affected by the SPU. The staff accepts licensee's evaluation because it is reasonable that the containment atmospheric mixing mechanism is unaffected by the SPU.

2.6.4.3 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 GDC-5, GDC-41, GDC-42, and GDC-43 as discussed above. Therefore, the staff finds the proposed SPU acceptable with respect to combustible gas control in containment.

2.6.5 Containment Heat Removal

2.6.5.1 Regulatory Evaluation

Spray systems are provided to remove heat from the containment atmosphere and from the water in the containment sump. The NRC staff's review in this area focused on (1) the effects of the proposed SPU on the analyses of the available NPSH to the CHR system pumps, and (2) the analyses of the heat removal capabilities of the spray water system. The NRC's acceptance criteria for CHR are based on GDC-38, insofar as it requires that the CHR 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 RG 1.82.

2.6.5.2 Technical Evaluation

The CHR system is designed to remove heat from the containment following a LOCA or a secondary system line break in order to reduce containment pressure and temperature. Major system components are the RWST, pumps, heat exchangers, spray headers, spray nozzles, and containment recirculation sumps. Each CPSES unit is equipped with two redundant, physically separated trains. Each train draws water from the common RWST during the injection phase and from separate recirculation sumps during the recirculation phase and sprays water into the containment atmosphere. Heat is removed from the containment by transferring it to the spray droplets.

The licensee evaluated the equipment performance and sump pH under the SPU post-accident conditions. For the injection phase, the NPSH available is unaffected because the pump draws water from the RWST. For the recirculation phase, the licensee confirmed the pump NPSH available is sufficient in accordance with RG 1.1 in which credit is not taken for the containment accident pressure. The licensee states that there are no changes in the pump flow, containment sump water level or pump available NPSH due to the SPU.

The licensee states that sump pH under post-accident conditions is unaffected as a result of SPU because the buffering solution concentration and the volume transferred to the sump are unchanged.

The licensee's evaluation of the thermal performance of CHR system heat exchangers under SPU post-accident conditions in regard to its capability to remove the required heat loads and maintain the long-term containment pressure and temperature below their design values is found to be acceptable as per Section 2.6.1 of this report.

The licensee states that the CHR system flow rates, operating pressures and temperatures are unchanged under SPU conditions. Therefore, its component and piping design pressures and temperatures are not affected.

The licensee evaluated the SPU impact on the response to GL 96-06. The GL states: "[t]hermally induced overpressurization of isolated water-filled piping sections in containment could jeopardize the ability of accident-mitigating systems to perform their safety functions and could also lead to a breach of containment integrity via bypass leakage. Corrective actions may be needed to satisfy system operability requirements." The licensee's evaluation concluded that no SPU changes are required in the water-filled piping that penetrate the containment that supply cooling water to the CHR system heat exchangers and no new relief valves are required and the existing relief valves are acceptable.

The licensee evaluated the SPU impact on its proposed response to GL 2004-02 which relates to resolution of the GSI 191. The resolution and the required actions confirm that post-accident debris blockage of the sump strainers will not prevent or degrade operation of the ECCS and CHR system operating in recirculation mode. The licensee's evaluation concluded that SPU does not affect the modification and actions that licensee will propose in its final response to GL 2004-02 because there are no changes in the pump flow, containment sump water level or pump available NPSH due to the SPU as stated above.

2.6.5.3 Conclusion

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

The NRC staff has reviewed the licensee's assessment of the impact that the proposed SPU would have on the previous resolution of the GL 96-06 issue of overpressurization of piping systems that penetrate the containment due to thermal expansion of the piping fluid and considers it as resolved. Therefore, the staff finds the proposed SPU acceptable with respect to GL 96-06 issue of overpressurization of piping systems that penetrates containment.

2.6.6 Pressure Analysis for ECCS Performance Capability

2.6.6.1 Regulatory Evaluation

Following a LOCA, the ECCS will supply water to the RV to reflood and, thereby, cool the reactor core. The core flooding rate will increase with increasing containment pressure. The 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 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.

2.6.6.2 Technical Evaluation

The licensee evaluated the SPU ECCS performance capability with the minimum containment back pressure in a separate LAR submitted in a letter dated July 31, 2007 (Reference 26). The NRC staff included its SE in a letter dated April 2, 2008 (Reference 27), which accepted the licensee's evaluation.

2.6.6.3 Conclusion

Based on the SE transmitted under Reference 27, the NRC staff determined that the SPU ECCS performance capability evaluated with the minimum containment back pressure is acceptable.

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

2.7.1.1 Regulatory Evaluation

The CR habitability systems for the CR envelope include radiation shielding, redundant air supply and filtration systems, redundant air-conditioning systems, fire protection, personnel protective equipment, first aid, food, water storage, emergency lighting, and sanitary facilities. The NRC staff reviewed the CR 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 NRC staff's review was to ensure that the CR can be maintained as the backup center from which technical support center (TSC) personnel can safely operate in the case of an accident. The NRC staff's review focused on the effects of the proposed SPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination. The NRC's acceptance criteria for the CR habitability system are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with postulated accidents, including the effects of the release of toxic gases; and (2) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the CR under accident conditions without personnel receiving radiation exposures in excess of 5 rem (roentgen equivalent man) whole body, or its equivalent, to any part of the body, for the duration of the accident. Specific review criteria are contained in SRP Section 6.4.

2.7.1.2 Technical Evaluation

The licensee evaluated the effects of SPU and states that there is an increase in dose for most events, except for the LOCA. The licensee further states that, since the CR will see the highest impact due to LOCA and the dose does not increase for this event, it is concluded that the radiological consequences to the CR will not be impacted by the SPU. Therefore, the radiological consequences to the CR remain within regulatory limits. The TSC is located in the control building, which is contained within the CR habitability envelope. The licensee has documented the SPU radiological consequences evaluation and results in Section 2.9 of the SPULR, which has been reviewed by the NRC staff. The NRC staff considers the SPU evaluation and results acceptable.

2.7.1.3 Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed SPU on the ability of the CR habitability system to protect plant operators against the effects of accidental releases of toxic and radioactive gases. The NRC staff concludes that the licensee has adequately accounted for the increase of radioactive gases that would result from the proposed SPU. Based on this, the NRC staff concludes that the CR habitability system will continue to meet the requirements of GDC-4. The NRC staff further concludes that the CR habitability system will continue to provide the required protection following implementation of the proposed SPU and meet the requirements of GDC-19.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

2.7.2.1 Regulatory Evaluation

The ESF atmosphere cleanup systems perform the function of post-accident fission product control and removal. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed SPU on system functional design, environmental design, and provisions to preclude temperatures in the adsorber section from exceeding design limits. The NRC's acceptance criteria for the ESF atmosphere cleanup systems 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 whole body, or its equivalent, to any part of the body, for the duration of the accident; (2) GDC-41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents; (3) GDC-61, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions; and (4) GDC-64, insofar as it requires that means shall be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs, and postulated accidents. Specific review criteria are contained in SRP Section 6.5.1.

2.7.2.2 Technical Evaluation

The systems that are included in the ESF atmosphere cleanup systems are (1) CSS, (2) emergency filtration and pressurization units in the control room area ventilation system (CRAVS), and (3) primary plant ventilation ESF exhaust units. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed SPU on system functional design and environmental design. The CRAVS includes two sets of high-efficiency particulate air (HEPA)/carbon filters for use during accident conditions, CR emergency filtration units, and the emergency pressurization units. The dose analysis for SPU operation presented in SPULR Section 2.9 indicates that the existing system and equipment are capable of maintaining the CR dose within regulatory requirements. The CSS, along with the sodium hydroxide injection, is designed to remove post-accident heat and fission products from the containment atmosphere. The licensee states that the SPU will increase the core radioactive source, but the offsite, and CR dose analysis presented in SPULR Section 2.9 demonstrate the ability of the existing CSS to maintain the releases within acceptable limits. The primary plant ventilation exhaust system includes four ESF exhaust units that maintain the Auxiliary, Fuel Handling, and Safeguards Buildings at a negative pressure during post-accident conditions. The units are equipped with HEPA filters, and carbon adsorbers to prevent the release of radioactive contamination into the atmosphere. The licensee states that the results of the dose analysis presented in SPULR Section 2.9 indicate that the SPU does not result in any increase in the duty of the ESF exhaust units and, therefore, no modifications to the equipment or operation of any of the ESF atmospheric cleanup systems is required. The NRC staff considers the SPU results acceptable and the requirements of GDC-19 and GDC-41 to be met.

2.7.2.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the ESF atmosphere cleanup systems. Based on its review, the NRC staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of GDC-41, GDC-61, and GDC-64. The NRC staff further concludes that the ESF atmosphere control systems will continue to provide the required fission product removal following implementation of the proposed SPU and meet the requirements of GDC-19.

2.7.3 Ventilation Systems

2.7.3.1 Control Room Area Ventilation Systems

2.7.3.1.1 Regulatory Evaluation

The function of the CRAVS (control room area ventilation system) is to provide a controlled environment for the comfort and safety of CR personnel and to support the operability of CR components during normal operation, AOOs, and DBA conditions. The NRC's review of the CRAVS focused on the effects that the proposed SPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the CRAVS. The NRC's acceptance criteria for the control building ventilation system are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) 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 whole body, or its equivalent to any part of the body, for the duration of the accident; 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 9.4.1.

2.7.3.1.2 Technical Evaluation

The CRAVS consists of the following major components: (a) CR area air conditioning units, (b) CR emergency filtration system, (c) CR emergency pressurization units, (d) CR normal supply fans, (e) CR normal exhaust fans, and (f) CR toilet and kitchen exhaust ventilation subsystem. The licensee determined that the proposed SPU has no effect on the ability of the CRAVS to provide a controlled environment for the comfort and safety of CR personnel and to support the operability of the CR components. The SPU impact of accident radiological consequences is provided in Section 2.9 of SPULR which has been reviewed by the NRC staff. The NRC staff considers the SPU evaluation and results acceptable.

2.7.3.1.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of CR personnel and to support the operability of CR components. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would

result from a DBA under the conditions of the proposed SPU, and associated changes to parameters affecting environmental conditions for CR personnel and equipment. The NRC staff also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the CRAVS will continue to meet the requirements of GDC-4 and GDC-60. The NRC staff further concludes that the CRAVS will continue to provide the required protection following implementation of the proposed SPU and meet the requirements of GDC-19.

2.7.4 Spent Fuel Pool Area Ventilation System

2.7.4.1 Regulatory Evaluation

The function of the SFP area ventilation system (SFPAVS) is to maintain ventilation in the SFP equipment areas, permit personnel access, and control airborne radioactivity in the area during normal operation, AOOs, and following postulated fuel handling accidents (FHAs). The NRC staff's review focused on the effects of the proposed SPU on the functional performance of the safety-related portions of the system. The NRC's acceptance criteria for the SFPAVS are based on (1) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents, and (2) GDC-61, insofar as it requires that systems which contain radioactivity be designed with appropriate confinement and containment. Specific review criteria are contained in SRP Section 9.4.2.

2.7.4.2 Technical Evaluation

The licensee states that the decay heat in the SFP will increase under SPU conditions, but the SFP water temperature during normal and abnormal SPU operation remains below design limits. Based on this, the licensee concluded that the SFPAVS will maintain the required temperature conditions for personnel and equipment during SPU operation. In a letter dated January 31, 2008 (Reference 9), in response to NRC staff RAIs, the licensee stated that the fuel building ventilation system and its coolers are designed to maintain suitable ambient conditions during normal operations and scheduled shutdowns and are designed for those conditions. During a LOCA, the fuel building ventilation system is shut down and cooling to the pump area is provided by emergency fan coil units. The licensee further clarified that the post-SPU conditions of operation of the SFP cooling system and its impact on SFP area ventilation has been analyzed by a calculation which concluded that a small increase in fuel decay heat at SPU is bounded by pre-SPU ventilation system heat loads based on the pool water temperatures remaining below pre-SPU design limits. In addition, the licensee states that a loss of SFP cooling will have no effect on the fuel building area ventilation system at SPU conditions. The NRC staff accepts licensee's evaluation because the SFP design temperature bounds SPU conditions and, therefore, the SFPAVS will maintain the required temperature conditions for personnel and equipment during SPU operation. The licensee states that primary plant ventilation system exhaust filters that collect the airborne radioactive particles are unaffected because the system will not change or design conditions are bounded for SPU conditions. Based on the evaluations performed under Sections 2.5.4.1 and 2.9.8 of this SE, the NRC staff accepts the licensee's evaluation.

2.7.4.3 Conclusion

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

2.7.5 Auxiliary and Radwaste Area and Turbine Area Ventilation Systems

2.7.5.1 Regulatory Evaluation

The function of the auxiliary and radwaste area ventilation system (ARAVS) and the turbine area ventilation system (TAVS) is to maintain temperature in the auxiliary building, radwaste areas, and turbine building areas, permit personnel access, and control the concentration of airborne radioactive particles in these areas during normal operation, AOOs, and after postulated accidents. The NRC staff's review focused on the effects of the proposed SPU 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, insofar as it requires that the plant design includes the means to control the release of radioactive effluents. Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4.

2.7.5.2 Technical Evaluation

The licensee evaluated the changes in heat loads under the SPU conditions in the areas served by the ARAVS and the TAVS to confirm that these systems are capable of performing their assigned functions. In a letter dated January 31, 2008 (Reference 9), in response to NRC staff RAIs, the licensee stated that the heat load changes due to the SPU are insignificant. The licensee also clarified a statement in the SPULR by stating that turbine building areas that are served by direct ventilation with the outdoor air normally experience room air temperature daily variation that dominate any temperature changes caused by the SPU. The changes were found to be insignificant to degrade essential system operation, to impact system capability to circulate sufficient air to prevent accumulation of flammable or explosive gases, or impact its ability to control airborne particulate material accumulation. The licensee states that the evaluation of the plant equipment changes for the SPU conditions did not require modification of these systems, and no plant equipment changes are required that could create a new potentially unmonitored radioactive release path. The licensee determined that an insignificant increase in heat load did not affect the ventilation equipment and the capability to control and minimize the release of airborne particles to the environment is maintained. The staff accepts the licensee's evaluation.

2.7.5.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the ARAVS and TAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU 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 NRC staff concludes that the ARAVS and TAVS will continue to meet the requirements of GDC-60. Therefore, the staff finds the proposed SPU acceptable with respect to the ARAVS and the TAVS. The effects of potential releases to the environment are acceptable.

2.7.6 Engineered Safety Feature Ventilation System

2.7.6.1 Regulatory Evaluation

The function of the ESF ventilation system (ESFVS) is to provide a suitable and controlled environment for ESF components following certain AOOs and DBAs. The NRC staff's review for the ESFVS focused on the effects of the proposed SPU on the functional performance of the safety-related portions of the system. The NRC staff's review also covered (1) the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESFVS 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 (e.g., storage batteries and stored fuel), and (3) the capability of the ESFVS to control airborne particulate material (dust) accumulation. The NRC's acceptance criteria for the ESFVS 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-17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of SSCs important to safety; 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 9.4.5.

2.7.6.2 Technical Evaluation

The ESFVS ventilation systems serve areas in the ESF Building, auxiliary Building and radwaste area, fuel Building, and EDG Building.

The licensee states that there will be an insignificant increase in heat load in these buildings under SPU accident conditions primarily due to the changes in the system operating conditions. The licensee evaluated the ESF building area temperature under SPU accident conditions and determined that it is unaffected because the increase in the heat load is insignificant.

The SPU evaluation of auxiliary building and radwaste area ventilation system is given in Section 2.7.5 of this report.

The SPU evaluation of spent fuel area ventilation system which is a part of the fuel building ventilation system is given in Section 2.7.4 of this report.

In SPULR Section 2.3.3, the licensee states that SPU condition will not increase the EDG loading. Therefore, the EDG building ventilation system will maintain the required temperature conditions under the SPU condition.

The licensee evaluated the systems under SPU conditions and ensured its capability of circulating sufficient air for preventing accumulation of flammable or explosive gases, and also its ability to control airborne particulate material accumulation. The licensee states that the evaluation of the plant equipment changes for the SPU conditions did not require modification of these systems, and no plant equipment changes are required that could create a new potentially unmonitored radioactive release path. The licensee determined that an insignificant increase in the heat load did not impact the ventilation equipment and the capability to control and minimize the release of airborne particles to the environment is maintained. The staff accepts licensee's evaluation.

The licensee states that SPU activities do not add any new components, nor do they introduce any new functions to existing components that would change the licensed system boundaries. In addition, the SPU does not add any new or previously unevaluated materials to the system because no modifications are necessary for the ESFVS components. System component internal and external environments remain within the parameters previously evaluated.

2.7.6.3 Conclusion

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

2.7.7 Other Ventilation Systems (Containment)

2.7.7.1 Regulatory Evaluation

The functions of the containment ventilation system is to remove heat from the containment atmosphere during normal operation, circulate air and remove radioactive materials from the containment atmosphere during normal operation, and provide pressure control under normal and accident conditions. The NRC staff's review focused on the effects of the proposed SPU on the functional performance of the system. The NRC's acceptance criterion for the system is based on GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes without loss of capability to perform their safety functions.

2.7.7.2 Technical Evaluation

The containment ventilation system consists of seven subsystems which are: (1) containment air recirculation and cooling system, (2) CRDM cooling system, (3) neutron detector well cooling system, (4) containment preaccess filtration system, (5) containment purge supply and exhaust system, (6) containment pressure relief system, and (7) reactor coolant pipe penetration cooling system. In order to verify that the containment ventilation system can perform its intended

functions under the SPU condition, the licensee evaluated the increase in its containment heat load during normal reactor operation. The result of the evaluation showed an increase of less than 0.15 ^{o}F in the containment bulk operating temperature from the current observed level at SPU conditions and does not exceed the maximum containment bulk air temperature of 120 ^{o}F. The licensee states that the minor temperature change in the process fluids for these systems can be adequately compensated for by the existing cooling coil units. The licensee states that SPU activities do not add any new components, nor do they introduce any new functions to existing components that would change the licensed system evaluation boundaries. In addition, the SPU does not add any new or previously unevaluated materials to the system because no modifications are necessary for the containment ventilation system components. System component internal and external environments remain within the parameters previously evaluated.

2.7.7.3 Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the containment ventilation system. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the capability of its subsystems to perform their intended functions. The NRC staff also concludes that containment ventilation system will continue to meet the requirements of GDC-2. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the containment ventilation system.

2.8 Reactor Systems

2.8.1 Fuel System Design

2.8.1.1 Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, channel boxes, 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 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 NRC 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 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 is provided in Matrix 8 of RS-001 (Reference 1).

2.8.1.2 Technical Evaluation

The fuel system in use at CPSES, Units 1 and 2 includes Westinghouse 17x17 fuel matrices of the VANTAGE+ design (Reference 7). The VANTAGE+ fuel includes ZIRLO cladding, midspan grids, and guide/instrument tubes, a debris filtering bottom nozzle, protective bottom grid, and pre-oxidized cladding. The licensee stated that the current operating cycles contain VANTAGE+ fuel assemblies with and without intermediate flow mixer (IFM) grids, the compatibility of which is evaluated and NRC-approved in WCAP-10445-NP-A (Reference 30).

The licensee stated that no mechanical changes will be made to the fuel system design; uprated fuel will continue to be of the VANTAGE+ mechanical design. The VANTAGE+ fuel in use at CPSES, Units 1 and 2 is designed for compliance with the fuel rod design criteria presented in SRP Section 4.2. Before and after the proposed uprate, the same design bases are applicable. The compliance of VANTAGE+ fuel with the design bases is discussed in WCAP-12610-P-A (Reference 31).

Because the licensee identified the applicable fuel design bases, and because these design bases will not change for uprate operation at CPSES, Units 1 and 2, the staff finds that the mechanical design for the uprated fuel, and for the currently loaded fuel, will be acceptable, provided that the phenomena that change as a result of the uprate are appropriately evaluated.

The licensee evaluated the fuel system design for its acceptability at uprated conditions. Increases in both core flow and temperature gradients will result from implementation of the proposed SPU. The licensee has evaluated assembly lift forces and hold-down force margin, conservatively assuming high burnup fuel assembly growth and hold-down spring relaxation.

The results of the licensee's evaluations demonstrate that the fuel system will perform acceptably under uprated conditions during a seismic event or a LOCA. For seismic events, evaluations demonstrated that fragmentation of the fuel rods does not occur as a result of the seismic loads, and that the ability to insert control rods is maintained. As a direct result of a LOCA blowdown load, fragmentation of the fuel rod will not occur and the ability to insert control

rods is maintained, and coolable geometry is maintained. Maximum loads for these events were calculated and compared to the allowable grid-crush strength.

Similar to evaluation at the currently licensed conditions, fuel rod performance evaluations for the uprated core considered compliance for all fuel designs in the core. The evaluations were based on a reference fuel system, and included two transition cycles and an equilibrium uprate cycle. To support fuel reloads, analyses will be performed on a cycle-specific basis using Westinghouse's NRC-approved computational fuel rod design tool, PAD4.0 (Reference 32). The PAD4.0 code accepts inputs for core performance and calculates the interrelated effects of temperature, pressure, clad elastic and plastic behavior, fission gas release, and fuel densification and swelling as functions of time and linear power. The code is approved to evaluate fuel to a maximum rod average burnup of 62,000 MWD/MTU. The NRC staff observes that this burnup limit may apply readily to VANTAGE+ assembly designs, but did not evaluate the acceptability of the extended burnup limit for re-insertion of previously irradiated Optimized Fuel Assemblies.

The fuel rod design analysis demonstrates acceptable performance of the fuel rods at uprated condition. The licensee evaluated rod internal pressure by analyzing gas inventories, rod internal volumes, and gas temperature. The clad stress and strain evaluation considered clad temperature and irradiation effects on yield strength. An evaluation of cladding oxidation and hydriding based on clad surface temperatures concluded that applicable temperature limits were satisfied, and base metal wastage of the ZIRLO grids and guide tubes were shown not to exceed the design limit at EOL. The hydrogen pickup criterion has been met, which demonstrates an acceptably limited loss of ductility due to hydrogen embrittlement resulting from the formation of zirconium hydride platelets. Thermal and mechanical modeling of the fuel pellets demonstrated acceptable fuel surface, average, and centerline temperatures. The clad fatigue evaluation used a limiting fatigue duty cycle consisting of daily load follow maneuvers, and the cumulative fatigue usage factor was less than the 1.0 design limit. The licensee stated that current fuel rod designs employing high-density fuel with improved in-pile stability and helium backfill pressure provide adequate assurance that axial gaps large enough to allow cladding flattening will not occur. The NRC-approved generic report, "Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel," WCAP-13589-A (Reference 33), concluded that clad flattening does not occur in Westinghouse fuel designs. A fuel growth evaluation demonstrates that there is adequate margin to the fuel rod growth design limit. Finally, generic analyses for Westinghouse fuel rod geometries show that instantaneous collapse of the VANTAGE+ fuel is precluded for differential pressures well in excess of the maximum expected differential pressure across the clad under operating conditions.

Based on its review of the licensee's application, the NRC staff concludes the following:

- The CPSES, Units 1 and 2 fuel system is acceptable with respect to its ability to withstand fuel system damage at uprated conditions. This conclusion is based on acceptable results of fuel rod performance evaluations of clad stress and strain, oxidation, clad fatigue, and internal pressure, and calculations of the hydraulic loads based on assembly lift and hold-down force margin.

- The CPSES, Units 1 and 2, fuel system is acceptable with respect to its ability to withstand fuel rod failure at uprated conditions. This conclusion is based on acceptable results of evaluations of rod hydriding and plenum clad support. It should be further noted that internal hydriding and clad collapse are primarily the result of manufacturing deficiencies, and are not uprate-related factors.

- The CPSES, Units 1 and 2 fuel system is acceptable with respect to fuel coolability. This conclusion is based on the fact that the licensee demonstrated that the hydrogen pickup criterion has been met, and that the internal rod pressure acceptance criterion to prevent DNB propagation is met, which prevents fuel rod ballooning.

2.8.1.3 Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed uprate on the fuel system design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed uprate 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 NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, GDC-10, GDC-27, and GDC-35 following implementation of the proposed uprate. Therefore, the NRC staff finds the proposed uprate acceptable with respect to the fuel system design.

2.8.2 Nuclear Design

2.8.2.1 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 anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. The NRC 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 (I&C) 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 RV 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 (Reference 1).

2.8.2.2 Technical Evaluation

Design changes associated with a power uprate 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 transient and accident analyses.

The licensee evaluated the CPSES, Units 1 and 2 nuclear design using core loading patterns for three cycles. These core loading patterns represent reference cores for two transition cycles and one equilibrium cycle. The licensee stated that the loading patterns were developed based

on projected energy requirements of approximately 515 EFPDs for CPSES, Units 1 and 2. As stated by the licensee, these loading patterns are not intended to represent limiting loading patterns, but were developed to demonstrate that enough margin exists between typical safety parameter values and their corresponding limits to allow flexibility in designing actual reload cores. This is illustrated in the subsequent sections that discuss the results of the licensee's transient analyses.

The following table depicts the nuclear design parameters of the uprated core in comparison to the current nuclear design. Ranges of reactivity coefficients are presented to account for the fact that the reactivity coefficients change during the life of the core. These ranges are employed in transient analyses to determine the response of the plant throughout the core life.

	Current Design Values	**Uprate Analysis Values**
Reactor Core Power (MWt)	3458	3612
Hot full power (HFP) Average Coolant Temp (°F)	589.2	574.2 – 589.2
Coolant System Pressure (psia)	2250	2250
Core Average Linear Heat Rate (kW/ft)	5.52	5.77
Most Positive Moderator Temperature Coefficient (MTC), <70% (pcm/°F)	+5.0	+5.0
Most Positive MTC, >70% (pcm/°F)	0.0	0.0
Most Positive Moderator Density Coefficient (MDC)	0.38	0.50
Doppler Temperature Coefficient	-2.241 to -0.785	-2.90 to -0.91
Doppler Only Power Coefficient	These parameters range in value. Refer to SPULR Table 2.8.2-1.	
Beta-Effective	0.0044 to 0.0070	0.0044 to 0.0075
Normal Operation Enthalpy Rise Hot Channel Factor	1.55	1.60
Normal Operation Axial Peaking	2.42	2.50

The practice of presenting evaluations of uprated cores based on projected typical values is acceptable to the NRC staff for two reasons. First, as the licensee stated, it demonstrates that appropriate safety margins can be maintained despite the higher energy level of the uprated core. This demonstration is shown not only by a comparison of the nuclear design parameters of the current core to an uprated core, but also by acceptable transient analysis results that incorporate the nuclear design of the uprated core. Second, the actual nuclear design of the core is cycle-specific. Therefore, the licensee will continue to use the applicable NRC-approved Westinghouse design and analytical tools in accordance with the NRC-approved reload method to generate the nuclear design of each cycle (Reference 34). In view of the typical nuclear design data presented by the licensee, and the fact that each cycle's core will be analyzed using NRC-approved methods, the NRC staff finds reasonable assurance that the CPSES, Units 1 and 2 uprated core nuclear design will remain acceptable.

2.8.2.3 Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the proposed SPU and fuel system change on the nuclear design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the nuclear design and has demonstrated that the fuel design limits will not be exceeded during normal or anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. Based on this evaluation and in coordination with the reviews of the fuel system design, thermal and hydraulic design, and transient and accident analyses, the NRC staff concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the applicable requirements of GDC-10, GDC-11, GDC-12, GDC-13, GDC-20, GDC-25, GDC-26, GDC-27, and GDC-28. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the nuclear design.

2.8.3 Thermal and Hydraulic Design

2.8.3.1 Regulatory Evaluation

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 (Reference 1).

2.8.3.2 Technical Evaluation

Consistent with conventional Westinghouse design approaches, the licensee provides assurance of compliance with GDC-10 using the oft-cited but unofficial ANS scale of events, Conditions I through IV (Reference 35).

For Condition I and II events, the licensee must assure that fuel damage is not expected, with the exception of a small number of fuel failures that are within the capability of the plant system to mitigate. For Condition III events, the reactor must be returned to a safe shutdown state. Although sufficient fuel damage might occur that precludes immediate resumption of operation, only a small fraction of fuel rods may be damaged. For Condition IV events, the core must remain intact with a coolable geometry.

For Condition I and II events, the design is completed to assure that there is at least a 95 percent probability with 95 percent statistical confidence that boiling transition will not occur on the limiting fuel rods. There is also at least a 95 percent probability with 95 percent confidence that the peak linear heat generating fuel rods will not exceed the uranium dioxide melting temperature.

To assure compliance with GDC-12, regarding thermo-hydro-dynamic instabilities, the licensee's core is designed such that:

- Fundamental mode total power oscillations are inherently stable due to the negative power coefficient of reactivity.
- Xenon oscillations in radial, azimuthal, and diametral overtone modes are heavily damped due to core design and the negative power coefficient of reactivity.
- First overtone mode xenon oscillations may occur, but reactor trip functions based on axial power imbalance will assure that such oscillations do not exceed SAFDL.
- Higher mode xenon oscillations are heavily damped due to inherent design features and the negative doppler coefficient of reactivity.

The licensee analyzes transients using the RETRAN (Reference 23) and LOFTRAN (Reference 36) system codes. These codes are used to simulate the reactor system response to the analyzed transients. Amendment No. 144 to both CPSES Facility Operating Licenses contains the NRC staff's approval of these codes as used to analyze the uprated reactor system performance (Reference 27). The system codes are used to generate the necessary inputs to the VIPRE code (Reference 38), which is then used to perform sub-channel analysis of DNB.

The licensee currently uses the Revised Thermal Design Procedure (RTDP) to analyze transient performance of DNB (Reference 39). RTDP is used in combination with the VIPRE sub-channel thermal-hydraulic analysis code, implementing the WRB-2 DNB correlation with a correlation limit of 1.17. Both the VIPRE code and the WRB-2 correlation are NRC-approved, and their use at CPSES specifically for uprated conditions has been previously reviewed and

approved by the NRC, as indicated in Amendment No. 144 to both CPSES Facility Operating Licenses (Reference 27).

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 code uncertainties. The RTDP establishes a design DNB ratio (DNBR) limit that statistically accounts for the effects of the key parameters on DNB. The RTDP is documented in WCAP-11397-P-A (Reference 39). The DNB design criterion reflects the guidance contained in Chapter 4.4 of the SRP, specifically, that the appropriate margin is contained in the RTDP statistical analysis to provide 95/95 confidence that the limiting fuel rods will not undergo transition boiling as discussed in the preceding paragraphs. As the RTDP considers the parametric uncertainties, thermal-hydraulic analyses are performed using input parameters at their nominal values.

An SAL DNBR is calculated, which provides for a certain amount of margin above the design limit discussed above. The SAL, which is higher than the design limit, provides a margin to offset the effect of rod bow and other DNBR penalties that may occur, as well as to provide the licensee with margin for operational flexibility.

Not all transients are analyzed using the WRB-2 correlation and/or the RTDP, however. For those transients where use of the WRB-2 correlation is restricted, the licensee used the W-3 correlation instead. These transients are those for which the analyzed conditions are predicted to fall outside the applicability range of the WRB-2 correlation based on any of pressure, local mass velocity, local quality, heated length, grid spacing, equivalent hydraulic diameter, equivalent heated hydraulic diameter, and distance from the last grid to the location of the critical heat flux (CHF). The W-3 correlation is used with a correlation limit of 1.3 (1.45 for pressures between 500 psia and 1000 psia) for analysis of the steam line break, and for analysis of the rod withdrawal event from subcritical conditions, for locations below the bottom non-mixing vane grid. The W-3 correlation is also approved for implementation at both CPSES units at uprated conditions (Reference 39).

After setting the SAL DNBR, the licensee uses the SAL to develop core limits, axial offset limits, and dropped rod limits. The maximum enthalpy rise hot channel factor is then developed based on these limits.

Thermal-hydraulic design analysis included consideration of both thermal design and best-estimate design bypass flows, which are both considered with thimble tube plugs installed and removed.

The analyses performed by the licensee considered a full reference core of VANTAGE+ fuel. For each core design, the thermal and hydraulic design and analysis will be performed in accordance with the NRC-approved Westinghouse reload methodology contained in WCAP-9273-P-A (Reference 34). In accordance with this method, the safety analysis and design limit DNBRs may change to reflect the core- and cycle-specific operating conditions and transient analysis results.

The NRC staff notes that the licensee is using acceptable methods, VIPRE, RETRAN, and LOFTRAN, to evaluate the thermal-hydraulic design of the core. The DNB correlations used in

these analyses will be appropriate for the core conditions, or supplanted as necessary. The methods in use will account for the relevant uncertainties in an acceptable manner. Based on the results presented in the Licensing Report, and on the fact that core- and cycle-specific analyses will be performed in accordance with NRC-approved methods, the staff finds this approach acceptable. Specific transients and accidents are evaluated further in Section 2.8.5 of this SE.

2.8.3.3 Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed SPU on the thermal and hydraulic design of the core and the RCS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the thermal and hydraulic design and demonstrated that the design

(1) Has been accomplished using acceptable analytical methods,

(2) Is equivalent to or a justified extrapolation of 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 NRC staff further concludes that the licensee has adequately accounted for the effects of the proposed uprate on the hydraulic loads on the core and RCS components. Based on this, the NRC staff concludes that the thermal and hydraulic design will continue to meet the requirements of GDC-10 and GDC-12 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to thermal and hydraulic design.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

2.8.4.1.1 Regulatory Evaluation

The NRC staff's review covered the functional performance of the control rod drive system (CRDS) to confirm that the system can affect 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 event of AOOs.

Specific review criteria are contained in SRP Section 4.6, and in Matrix 8 of RS-001 (Reference 1).

2.8.4.1.2 Technical Evaluation

The CRDS provides positive core reactivity control through the use of movable control rods. The movable control rods provide reactivity control for all modes of operation inclusive of all plant conditions from the cold shutdown condition to the full-load condition. The CRDS, in conjunction with the protection system, must actuate the control rods to effect safety-related functions when necessary to provide core protection and assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems.

The NRC staff reviewed the licensee's analysis related to the CRDS at the SPU power level of 3612 MWt. The licensee performed various analyses which included accident and transient analyses for the SPU conditions, analyses and evaluations of the impact of the SPU on the structural integrity of the CRDS during normal, transient, and accident conditions, and analyses and evaluations of the effects of the SPU on the CRDS cooling system. The potential impact of the SPU on the CRDS results from the temperature effects associated with increasing the reactor core thermal power to 3612 MWt. Because of possible temperature effects from the SPU, thermal aging and the structural integrity of the CRDM (insulation and potting materials

used in the construction of the electro-magnetic coils) were evaluated to validate the CRDS cooling system.

The licensee stated that the temperature of the RV head is the same as the RV inlet temperature. In response to an NRC staff RAI, the licensee provided the results of an evaluation that demonstrated a slight decrease in RV head temperature (from 559.6 °F to 558 °F) (Reference 7). Because the maximum RV head temperature changes only marginally as a result of the SPU, the licensee concluded that the performance of the CRDS cooling system is unaffected by power uprate. As the primary source of heat to the CRDS cooling system is conduction and convection from the RV head, the NRC staff agrees with the licensee that the CRDS cooling functions are unaffected by SPU.

There are no physical changes required to the CRDS, operating coil stacks, power supplies, solid state electronic control cabinets, or the CRDS. 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 (TS 3.1.4, Reference 40).

Based on the NRC staff's review of the functional design of the CRDS, the staff concludes that the CRDS will operate acceptably at uprated conditions. The NRC staff based its conclusion on (1) the fact that CRDS evaluations are performed at a temperature that is bounding of the RV head temperature; (2) the fact that no physical changes are required to the CRDS; and (3) the fact that the CPSES, Units 1 and 2, TS-required verification of control insertion times will provide additional verification of CRDS operability at uprated conditions prior to operation.

2.8.4.1.3 Conclusion

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

2.8.4.2 Overpressure Protection During Power Operation

2.8.4.2.1 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 non-brittle 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 (Reference 1).

2.8.4.2.2 Technical Evaluation

Overpressure protection for the RCPB during power operation is important for the following AOOs:

1. Loss of electrical load and/or turbine trip

2. Uncontrolled rod withdrawal at power

3. Loss of reactor coolant flow

4. Loss of normal feedwater (LONF)

5. LOOP to the station auxiliaries

The first event, loss of electrical load and/or turbine trip, is the most limiting AOO with respect to the potential for overpressurization of the RCS.

According to SRP Section 5.2.2, it is necessary to demonstrate that the CPSES, Units 1 and 2 safety valve capacities continue to be sufficient to limit RCS pressure to less than 110 percent of the RCPB design pressure (as specified by the ASME Code (Reference 41), during the most limiting AOO, assuming the effective reactor scram is derived from the second safety-grade signal from the RPS.

For this purpose, the licensee has provided the RETRAN analysis results, including transient plots and sequence of events tables, for the loss of external electrical load/turbine trip analysis, for both CPSES units. In these cases, the reactor is assumed to trip from the second safety-grade reactor trip signal (SRP 5.2.2 II.3.B.iii), from the OTN-16 trip logic (Reference 12). A resulting peak RCS pressure, that is less than the safety limit (2748.2 psia), demonstrates the adequacy of the plants' RCS overpressure protection capabilities. The analysis results indicate that the peak RCS pressures, for CPSES, Units 1 and 2, are 2733.8 psia and 2744.2 psia, respectively. The analysis results also show that the first safety-grade reactor trip signal (not credited) is the high-pressurizer pressure reactor trip signal.

Results of the loss of external electrical load/turbine trip analysis, provided in Section 2.8.5.2.1 of the SPULR, indicate that when the reactor is tripped from the first safety-grade reactor trip signal, on high-pressurizer pressure, the peak RCS pressures, for CPSES, Units 1 and 2, are 2734.7 psia and 2746.0 psia, respectively. These peak RCS pressures are higher than the RCS peak pressures that are obtained by crediting the second safety-grade reactor trip because they are based upon the more conservative parametric assumptions of safety analyses, not the better-estimate assumptions of the design analyses that are used to size components for overpressure protection when operating at power.

2.8.4.2.3 Conclusion

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

2.8.4.3 Overpressure Protection During Low-Temperature Operation

2.8.4.3.1 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 non-brittle 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 the SPU on the P-T limit curves and PTS per 10 CFR 50.61.

2.8.4.3.2 Technical Evaluation

The staff's evaluation of the P-T limit curves is addressed in 2.1.2.2 of this SE; the staff's evaluation of PTS is evaluated in Section 2.1.3 of this SE. The licensee concluded that no change to the P-T limit curves was necessary, and that the current cold overpressurization analysis remains bounding. As a result, the licensee concluded that the Low-Temperature Overpressure Protection setpoint need not change. Based on the staff's acceptable findings of the PTS evaluations and the P-T limit curves in Section 2.1 of this SE, the staff finds the licensee's conclusions acceptable.

2.8.4.3.3 Conclusion

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

2.8.4.4 Residual Heat Removal System

2.8.4.4.1 Regulatory Evaluation

The RHR system is used to 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 SPU 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.

GDC-34 states that a system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that SAFDLs and the design conditions of the RCPB are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite power operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

2.8.4.4.2 Technical Evaluation

The RHR system, in conjunction with the steam and power conversion system, is designed to transfer the fission product decay heat and other residual heat from the reactor core within acceptable limits. The transfer of the heat removal function from the steam and power conversion system to the RHR system occurs when the RCS is at approximately 350 °F and 425 psig.

RHR is not the only design function of the RHR system. Portions of the RHR system support ECCS design functions. During plant cooldown, a portion of the RCS flow is diverted to the CVCS for RCS purification and inventory/pressure control.

The RHR system is comprised of two RHR pumps, two heat exchangers, and associated piping, cabling, and electric power sources, as described in CPSES, Units 1 and 2 FSAR Section 5.4.7. It contains suitable redundancy to perform its function with a single active component failure, because once the RCS conditions allow the RHR system to be placed in service, the remaining cooldown can be accomplished with either one or two trains of RHR in service. The consequence of cooling down with a single RHR system train in service is a longer cooldown time, and the SPU will not affect this function. Therefore, the staff finds the proposed SPU acceptable with respect to the ability of the RHR system to withstand a single failure at uprated conditions.

Because of the higher energy design of the uprated core, the proposed SPU will result in an increased decay heat load. Accordingly, the plant cooldown times are affected by the increase in decay heat load.

The licensee evaluated RHR system performance at uprated power levels in consideration of (1) normal operational requirements, (2) forced plant cooldown, (3) fire-safe shutdown, and (4) safety-grade cold shutdown. Functionally, the RHR system will be placed in service once the RCS temperature is reduced from its no-load value, 557 ºF, to RHR system entry conditions, 350 ºF. The licensee stated that, for normal cooldown, this evolution will take place within 4 hours. With two RHR system heat exchangers and pumps in service, based on RHR system entry within 4 hours following reactor shutdown, the plant cooldown time to achieve 140 °F will increase from a current value of 28 hours to approximately 33 hours. By placing the RHR system in service 12 hours after shutdown, with a single train of RHR, the plant can be brought to 200 °F in less than 24 hours after initiation. Fire safe shutdown requires that cold shutdown (200 °F) be achieved within 72 hours following reactor shutdown. The licensee stated that, with one train of RHR and CCW available, cold shutdown can be achieved approximately 8 hours after RHR initiation, with a potential extension of the RHR entry time of 6 hours due to uncertainty in strap-on resistance temperature detectors used for temperature indication from the remote shutdown panel. In consideration of this increase, and the 8-hour cooldown time, the time required to reach 200 °F in a fire-safe shutdown scenario remains within the 72-hour

acceptance criterion. The licensee stated that safety-grade cold shutdown can be attained within 36 hours, which includes any time required for manual actions.

The proposed SPU at CPSES, Units 1 and 2 results in increases to the time required to attain cold shutdown conditions. The licensee has calculated the predicted cooldown times for normal cooldown, forced plant cooldown, fire-safe shutdown, and safety-grade cold shutdown as described in BTS 5-1 of SRP Section 5.4.7 (BTP 5-4 in recently issued Revision 3 of the SRP). The NRC staff has reviewed the licensee's assumptions regarding these analyses, including RHR exchanger performance parameters, and verified that they are consistent with the current licensing basis, and hence, reflective of the functional capabilities of the RHR system.

For normal shutdown, the licensee calculated the increased cooldown time. The increased time is acceptable because it is reflective of the RHR performance at uprated conditions, and because there is no design criterion for normal plant cooldown time. For forced plant cooldown conditions, the licensee is required to demonstrate that the RHR system can cool the RCS from hot shutdown in a reasonable period of time. The NRC staff considers the licensee's 24-hour criterion acceptable, because at 24 hours, the cooldown time is consistent with the normal cooldown time and the safety-grade cold shutdown time. The licensee has demonstrated its compliance with the 72-hour fire-safe shutdown criterion, which the NRC staff also finds acceptable. Finally, the licensee demonstrated that the plant can attain safety-grade cold shutdown within 36 hours, which the NRC staff considers to be a reasonable amount of time.

2.8.4.4.3 Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed SPU on the RHR system. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU 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 NRC staff concludes that the RHR system will continue to meet the requirements of GDC-4, GDC-5, and GDC-34, as well as SRP Section 5.4.7 (Reference 29), following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU 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 a Steam Generator Relief or Safety Valve

2.8.5.1.1.1 Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to a power level increase and a decrease in shutdown margin (SDM). 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 (Reference 1).

2.8.5.1.1.2 Technical Evaluation

2.8.5.1.1.2.1 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. Demonstrating that CHF is not exceeded, and fuel cladding integrity is maintained, is accomplished by ensuring that the minimum DNBR remains greater than the 95/95 DNBR SAL in the limiting fuel rods. Specific review criteria are found in SRP Section 15.1.1-4.

The licensee used the NRC-approved RETRAN computer code to analyze the RCS and core response to the excessive heat removal due to a feedwater system malfunction, given the SPU conditions. DNBR evaluations were performed with the NRC-approved RTDP.

Reducing feedwater temperature when the plant is operating at full SPU power is more limiting, with respect to minimum DNBR, than reducing feedwater temperature at lower power levels. The licensee provides the results of hot-full power (HFP) analyses, assuming automatic and manual rod control. The limiting case, assuming manual rod control, produces a minimum DNBR of 1.90, which exceeds the 95/95 DNBR SAL of 1.61. In this case, the reactor is tripped when the OPN-16 trip setpoint is reached. Minimum DNBR is reached as the rods are being inserted into the core. The turbine is tripped 2 seconds after OPN-16 trip setpoint is reached. The NRC staff finds these results to be reasonable and expected.

The increase in feedwater flow cases were considered at hot-zero power (HZP), as well as at HFP. At HZP, the core cooldown produced by the increase in feedwater flow is exceeded by the core cooldown produced by a steam system piping failure (also considered at HZP). Therefore, the licensee concluded that this case is bounded by a steam system piping failure. The NRC staff agrees. At HFP, the licensee analyzed cases assuming failure of the feedwater control valve in one and two feedwater supply loops, with and without automatic rod control. The increase in feedwater flow case that assumed failure of the feedwater control valve in one feedwater supply loop, without automatic rod control, was the limiting case, yielding a minimum DNBR of 2.10. Basically, the increase in feedwater flow causes reactor power to rise and plateau at a new level. Similarly, DNBR falls and levels off at a new level. Operation continues under these stable conditions until the high-high SG water level is reached, which causes the turbine to trip and the feedwater isolation valves to shut. The reactor is tripped from the turbine trip signal. This can be problematic, since the reactor trip from turbine trip is not considered to be as reliable as other reactor trip signals. The turbine trip signal originates in the turbine building, which is not seismically qualified. However, the staff does not consider the reactor trip to be the direct mitigation for the increase in feedwater flow event. The mitigation for this event is feedwater isolation. The NRC staff finds these results to be reasonable and expected.

The 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 SPU program. Therefore, the staff found the

proposed SPU program acceptable with respect to the excessive heat removal due to feedwater system malfunction event.

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

Increase in steam flow and inadvertent opening of an SG relief or safety valve are excessive load increase incidents. They are AOOs that are 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 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. It is also important to prevent AOOs from developing into postulated accidents without the occurrence of other, independent failures (Reference 35). Specific review criteria are found in SRP Section 15.1.1-4.

The increase in steam flow event, or excessive load increase event, is considered as a 10 percent step-load increase at HFP. This event could be caused by an operator error, or an equipment malfunction in the steam dump control or turbine speed control. The plant design can tolerate a 10 percent step-load increase or a 5 percent per minute ramp load increase in the range of 15 to 100 percent of full power without tripping. Higher load increases or higher rates of load increase could lead to a reactor trip. The SPULR refers to the analysis of FSAR Section 15.1.3.3, which indicates that a 10 percent load increase would cause reactor power to increase and stabilize at a higher power level. No reactor trip would be demanded. No analysis is necessary to demonstrate that the minimum DNBR would remain above the DNBR SAL of 1.61, even at SPU conditions. This is verified by consulting SPULR Figure 2.8.5.0-2, Illustration of OTN-16 and OPN-16 protection. In this figure, increasing rated thermal power from 1.0 to 1.1, at the maximum value of nominal core inlet temperature of 558 °F (from SPULR Table 1.1-1), would not cross either of the OTN-16 or OPN-16 protection lines. Since the OTN-16 protection line causes a reactor trip before the core thermal conditions can reach the DNBR SAL, and the OPN-16 protection line prevents the linear heat rate from exceeding its SAL, the staff concludes that the proposed SPU is acceptable with respect to the excessive load increase incident.

2.8.5.1.1.3 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 NRC 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 NRC staff concludes that the plant will continue to meet the requirements of GDC-10, GDC-15, GDC-20, and GDC-26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the events stated.

2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment

2.8.5.1.2.1 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 SDM to be lost. A return to power following a steam pipe rupture is a concern primarily because of the high-power peaking factors that would exist assuming the most reactive RCCA to be stuck in its fully withdrawn position. RPS and safety systems are actuated to mitigate the transient. The core is shut down by boric acid injection into the RCS by the safety-injection system. The rupture of a major steam line is the most-limiting cooldown transient. When it is analyzed at HZP, no decay heat assumed. Decay heat would partly offset the cooldown, and reduce the post-trip return to power. Although this event is classified as a postulated accident (Reference 3), it is analyzed to meet AOO acceptance criteria.

Postulated accidents are equivalent to ANS Condition IV events, and AOOs are equivalent to ANS Condition II and III events, as described in SRP Section 15.0. The acceptance criteria for AOOs are based on CHF not being exceeded. The staff's review focused on the core response to the MSLB event. Specific review criteria are found in SRP Section 15.1.5.

2.8.5.1.2.1 Technical Evaluation

2.8.5.1.2.1.1 Steam System Piping Failures at HZP

The licensee used the RETRAN computer code to simulate the NSSS response to the HZP MSLB transient and to provide dynamic core conditions to the VIPRE thermal-hydraulic code and Advanced Nodal Code (ANCO) core physics code. The VIPRE code, employing the W-3 correlation (due to local conditions outside the WRB-2 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 staff for the MSLB analysis.

HZP conditions were modeled with four loops in service, assuming there was no SG tube plugging (to maximize the heat transfer rate). The available SDM was assumed to be 1.30 percent delta-k/k ($\Delta k/k$).

The largest possible, effective steam line break size is 1.388 square feet, the area of the flow restrictors in the steam exit nozzles of the Model Δ76 (CPSES, Unit 1) and Model D-5 (CPSES, Unit 2) SGs. The licensee analyzed cases of this break size assuming that offsite power is, and is not available. The safety-injection system is actuated from the low-steam line pressure signal.

Based upon the input parameters, assumptions, and modeling techniques described in SPULR Section 2.8.5.1.2.2.1, the NRC staff finds that the HZP MSLB transient simulation and the identification of the limiting cases are acceptable. The limiting CPSES, Unit 1 and CPSES, Unit 2 HZP MSLB cases demonstrate that the calculated minimum DNBR (2.861 for a thimble cell) remains above the DNB SAL of 1.45, ensuring that fuel clad failure does not occur.

2.8.5.1.2.1.2 Steam System Piping Failures at Hot Full Power

The purpose of the HFP MSLB analysis is to demonstrate that core protection is maintained prior to and immediately following a reactor trip. The MSLB is also known as the pre-trip MSLB. After reactor trip, the HZP MSLB (above) applies. The HZP MSLB is also known as the post-trip MSLB.

The current licensing basis for the CPSES units does not include a specific assessment of the pre-trip power excursion portion of the MSLB event. The respective sections of the CPSES, Unit 1 and CPSES, Unit 2 FSAR 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 also used the RETRAN code to simulate the NSSS response to the HFP MSLB transient and to provide dynamic core conditions to the VIPRE thermal-hydraulic code (Reference 38) and ANCO core physics code (Reference 42). The VIPRE computer code, employing the WRB-2 correlation above the first mixing vane grid and the W-3 correlation below, was used to calculate the minimum DNBR during the transient.

SPULR Section 2.8.5.1.2 describes the input parameters and assumptions used in the MSLB analyses. Tables 2.8.5.1.2.2.2-1 and 2.8.5.1.2.2.2-2 list the sequences of events of the limiting pre-trip MSLB scenarios for CPSES, Unit 1 and CPSES, Unit 2, respectively. In both units, the limiting break size corresponds to the largest possible break size, 1.388 square feet at the SG outlet flow restrictors, since the reactors are tripped by only the OPN-16 trip signal. The low-steamline pressure reactor trip would occur later, due to the effect of dynamic compensation in the trip signal logic. The limiting case, with respect to minimum DNBR, occurs in CPSES, Unit 2, wherein the minimum DNBR is 1.963 (thimble cell), which exceeds the DNBR SAL of 1.61. The limiting case, with respect to peak linear heat rate, occurs in CPSES, Unit 1, wherein the peak linear heat rate is 21.6 kilowatts per foot (kW/ft), which is less than the peak linear heat rate SAL of 22.4 kW/ft.

The limiting CPSES, Unit 1 and CPSES, Unit 2 pre-trip MSLB cases demonstrate that the calculated minimum DNBR remains above the DNB SAFDL, and the peak linear heat rate remains below the peak linear heat rate SAL, thus ensuring that fuel rod failure does not occur.

2.8.5.1.2.2 Conclusion

Based upon satisfying the more restrictive Condition II acceptance criteria, the NRC staff finds that the results of the CPSES, Units 1 and 2 power uprate pre-trip and post-trip MSLB analyses are acceptable. The analyses were conducted, at power uprate conditions, considering each unit's model of SGs.

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

2.8.5.2.1.1 Regulatory Evaluation

A number of initiating events may result in unplanned decreases in heat removal by the secondary system. These events result in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the 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 (Reference 1).

2.8.5.2.1.2 Technical Evaluation

A major LOL 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 AOO acceptance criteria applicable to this event are that (1) CHF is not exceeded, (2) pressure in the RCS and MSS are maintained below 110 percent of the design pressures values, and (3) the event does not develop into a more serious plant condition without the occurrence of another, independent fault. Specific review criteria are found in SRP Section 15.2.1-5.

The NRC staff agrees that the limiting loss of heat sink event is the turbine trip or the loss of condenser vacuum (which leads to a turbine trip). These events are equivalent, since their analyses share two key assumptions: no direct reactor trip on turbine trip, and no steam

dumping to the condenser. If steam dumping to the condenser is not available, then the steam is relieved through the MSSVs. The reactor is assumed to be tripped by the high-pressurizer pressure signal, the OTN-16 signal, or the OPN-16 signal.

The licensee analyzed three cases for a complete LOL from full power at SPU conditions: (1) with pressure control, (2) with automatic pressure control and minimum SG tube plugging, and (3) without automatic pressure control and maximum SG tube plugging.

Case (1) assumes the operation of pressurizer sprays and pressurizer PORVs. This tends to limit the RCS pressurization, delay reactor trip from the high-pressurizer pressure signal, and thereby reduce the resultant DNBR. Case (1), therefore, is analyzed to evaluate the minimum DNBR that could be generated by this event. RTDP is applied in this analysis.

Case (2) assumes the operation of pressurizer sprays and pressurizer PORVs, and a minimum level of SG tube plugging. This tends to limit the RCS pressurization, delay reactor trip from the high-pressurizer pressure signal, and increase primary-to-secondary heat transfer rate; and thereby increase SG shell-side pressure. Case (2), therefore, is analyzed to evaluate the maximum MSS pressure that could be generated by this event. RTDP conditions are not applied in this analysis.

Case (3) does not assume the operation of pressurizer sprays and pressurizer PORVs; but does assume a maximum level of SG tube plugging. This tends to reduce primary-to-secondary heat transfer rate, and thereby increase RCS pressure. Case (3), therefore, is analyzed to evaluate the maximum RCS pressure that could be generated by this event, and test the relief capacity of the pressurizer safety valves. RTDP conditions are not applied in this analysis.

Case (1), performed for DNBR evaluation, yielded a minimum DNBR of 1.98 (in CPSES, Unit 2), which is above the DNBR SAL of 1.45. The reactor trip was demanded by the OTN-16 trip signal, and the minimum DNBR occurred as the rods were falling into the core.

Case (2), performed to calculate the maximum MSS pressure, yielded a peak MSS pressure of 1298.4 psia (in CPSES, Unit 1), which is below the steam system pressure SAL (110 percent of the design value or 1318.2 psia). The reactor trip was demanded by the OTN-16 trip signal, and the peak MSS pressure occurred shortly after the rods had been fully inserted into the core.

Case (3), performed to calculate the maximum RCS pressure, yielded a peak RCS pressure of 2746.0 psia (in CPSES, Unit 2), which is below the RCS pressure SAL (110 percent of the design value or 2748.2 psia). The reactor trip was demanded by the high-pressurizer pressure trip signal, and the peak RCS pressure occurred as the rods were falling into the core.

None of the cases predicted a water-solid pressurizer would result. The maximum water volume, <1620 cubic feet, was attained in Case (2). Both units are equipped with 1800 cubic feet pressurizers. Therefore, the pressurizer PORVs, if opened, would not be required to relieve water, and can be expected to reseat completely. This AOO would not develop into a more serious plant condition, caused by a stuck-open pressurizer PORV.

The 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 SPU. The staff concluded that the CPSES, Units 1 and 2 loss of external electric load/turbine trip analyses at SPU conditions show that CPSES will continue to meet applicable regulatory requirements following implementation of the SPU. Therefore, the staff found the proposed SPU program acceptable with respect to the loss of external electrical load event.

2.8.5.2.1.3 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 NRC 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 NRC staff concludes that the plant will continue to meet the requirements of GDC-10, GDC-15, and GDC-26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the events stated.

2.8.5.2.2 Loss of Nonemergency AC Power to the Station Auxiliaries

2.8.5.2.2.1 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 (Reference 1).

2.8.5.2.2.2 Technical Evaluation

The loss of non-emergency AC power, an AOO, cuts off all power to the station auxiliaries and trips all RCPs. The reactor and turbine trip, the RCPs coast down, the 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 AOO acceptance criteria applicable to this event are that (1) CHF is not exceeded, (2) pressure in the RCS and MSS are maintained below 110 percent of the design pressures values, and (3) the event does not develop into a more serious plant condition without the occurrence of another, independent fault. Specific review criteria are found in SRP Section 15.2.6.

Analyses for the loss-of-AC-power (LOAC) event are not reported in the SPURL, since this event is bounded by the complete loss-of-flow event, SPULR Section 2.8.5.3, with respect to the DNBR SAL, by the LOL/turbine trip event, SPULR Section 2.8.5.2.1, with respect to RCS pressure and MSS pressure SALs, and by the LONF event with LOAC, SPULR Section 2.8.5.2.3, with respect to the capabilities of RCS natural circulation and the AFW system to remove stored and residual heat. The LONF event with LOAC analysis also demonstrates that a more serious plant condition cannot develop from this event, since the results does not indicate the pressurizer would become water-solid.

The staff agrees with this approach, since it is consistent with the results of the aforementioned analyses in this SPULR, and with results of analyses for these events that have been performed for other, similarly designed plants.

The staff concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed SPU, with respect to the LOAC power to the plant auxiliaries.

2.8.5.2.2.3 Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of nonemergency 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. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC-10, GDC-15, and GDC-26 following implementation of the proposed

SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the loss of nonemergency AC power to station auxiliaries event.

2.8.5.2.3 Loss of Normal Feedwater Flow

2.8.5.2.3.1 Regulatory Evaluation

A LONF 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. 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 (Reference 1).

2.8.5.2.3.2 Technical Evaluation

A LONF, an AOO, results in a reduction in the capability of the secondary system to remove heat from the primary side. The loss of heat sink requires the reactor trip and an alternate supply of feedwater be supplied to the SGs. Following reactor trip, it is necessary to remove residual heat and RCP heat to prevent RCS pressurization and loss of primary system water inventory through the pressurizer relief and safety valves. If enough RCS inventory is lost, then

core damage could occur. Since the reactor is tripped before the SG heat transfer capability is reduced, the primary system conditions never approach those that would result in a violation of the limit DNBR. The 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 safety-injection signal, on LOOP, or on trip of all main feedwater pumps.

The SPULR (Section 2.8.5.2.3) also indicates the AFW system will be started by the ATWS mitigation system actuation circuitry (AMSAC) actuation signal. The staff notes that, while AMSAC would be available for AFW actuation, crediting its operation in a LONF analysis could be problematic, since the ATWS Rule (10 CFR 50.62) requires the AMSAC to be diverse from the RPS and reliable; but not necessarily safety-grade. The NRC staff did not consider the availability of an AFW initiation signal from the AMSAC.

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 AOO acceptance criteria applicable to this event are that (1) CHF is not exceeded, (2) pressure in the RCS and MSS are maintained below 110 percent of the design pressures values, and (3) the event does not develop into a more serious plant condition without the occurrence of another, independent fault. Specific review criteria are found in SRP Section 15.2.7.

The LONF transient was analyzed using the RETRAN computer code, at SPU conditions. LONF events with and without offsite power were considered. RCP heats of 20 MWt and 16 MWt were added to the cases with and without offsite power, respectively. The SG low-low water level reactor trip setpoint was assumed to be set at 0 percent of narrow range span (NRS) for CPSES, Unit 1 (Model Δ76 SGs), and 10 percent of NRS for CPSES, Unit 2 (Model D-5 SGs). A conservatively high core residual heat generation rate was assumed, based on the ANS 5.1-1979 Decay Heat model, +2σ for uncertainties (Reference 43). SG tube plugging levels of both 0 percent and 10 percent were considered. AFW system flow, from both MDAFPs, was assumed to begin 60 seconds after the SG low-low water level setpoint was reached, and this flow was split equally among the four SGs. The worst single failure modeled was the loss of the TDAFP.

With respect to RCS and MSS overpressurization, the staff agrees that the LONF would be bounded by the loss of load/turbine trip (LOL/TT) transient. Both of these transients represent a reduction in the heat removal capability of the secondary system. For the LOL transient, the turbine trip is the initiating event, and so the power mismatch between the primary and secondary side would be greater.

The LONF event without offsite power is evaluated to test the DNBR SAL, since this event involves a core flow reduction, after the RCPs lose power, as well as the RCS heatup/pressurization due to the power/heat sink mismatch. With respect to DNB, the LONF event without offsite power is bounded by the complete loss-of-flow event, in which the effect of the RCP coastdown on DNBR, is not offset, as much, by the effect of RCS pressurization that

would be characteristic of a LONF. The minimum DNBR, for the complete loss-of-flow event (SPULR Section 2.8.5.3) is 1.90, which exceeds the applicable DNBR SAL of 1.61.

Satisfaction of the third acceptance criterion, that the LONF does not develop into a more serious plant condition without the occurrence of another, independent fault, is demonstrated by showing that 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. Reactor coolant water cannot be discharged through the pressurizer relief or safety valves if the pressurizer does not become water-solid. The SPULR indicates that the maximum pressurizer water volume, predicted for any of the LONF cases, is 1748 cubic feet, which is less than the total pressurizer volume (1800 cubic feet). Therefore, the licensee concludes, and the staff agrees, that the LONF would not develop into a more serious plant condition without the occurrence of another, independent fault.

The 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 SPU conditions bound current licensed power operation of the CPSES units. Therefore, the staff found the proposed SPU acceptable with respect to the LONF event.

2.8.5.2.3.3 Conclusion

The NRC staff has reviewed the licensee's analyses of the LONF 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 NRC 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. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC-10, GDC-15, and GDC-26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the normal feedwater flow event.

2.8.5.2.4 Feedwater System Pipe Breaks Inside and Outside Containment

2.8.5.2.4.1 Regulatory Evaluation

A major FLB, an ANS Condition IV event, is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the SGs to maintain shell-side fluid inventory. Depending upon the size and location of the break and the plant operating conditions at the time of the break, the break could cause either an RCS cooldown (by excessive energy discharge through the break) or an RCS heatup (by reducing feedwater flow to the affected RCS). 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 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;

(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 non-brittle 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 (Reference 1).

2.8.5.2.4.2 Technical Evaluation

Depending on break flow quality, the FLB can result in either an RCS cooldown or heatup. Since the steamline break analysis addresses the RCS cooldown, the FLB is evaluated as an event 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 core 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, has adequate capacity to remove decay heat, to prevent overpressurization of the RCS, and to prevent uncovery of the core.

The licensee used the RETRAN computer code to analyze the FLB event (Reference 23). The analyses model a simultaneous loss of main feedwater to all SGs and subsequent reverse blowdown of the faulted SG. The RETRAN FLB methodology was previously reviewed and approved by the NRC staff. A number of cases of FLB have been analyzed. Based on these analyses, it has been shown that the most limiting feedwater line ruptures are the double-ended rupture of the largest feedwater line, occurring at full power with and without LOOP (Reference 23). The full double-ended pipe break of the largest feedwater line would correspond to an effective break size of 1.12 square feet for CPSES, Unit 1 (Model Δ76 SGs), and 0.22 square feet for CPSES, Unit 2 (Model D-5 SGs).

The staff noted that it may be possible that the largest possible break size may not yield the most conservative results. In a review of another licensee's application for a power uprate, the NRC staff had questioned whether the Westinghouse methodology (Reference 23) would accurately identify the limiting break size. As a result of the staff's concerns, an issue report had been entered into the Westinghouse Corrective Action Process to investigate the effects of varying break size on the NOTRUMP low-SG level trip mass, the break flow enthalpy, and on the overall RETRAN simulation. The NRC staff finds that this is an acceptable disposition of the break size.

The FLB event can generate a harsh environment in the vicinity of the SG water level sensing reference legs, resulting in false high readings that can delay or prevent a reactor trip on SG low-water level. An error allowance, to account for this effect, has been included in the low-water level trip setpoints for the Δ76 and the D-5 SGs, and in the FLB accident analyses. The low-low SG water level setpoint, used for reactor trip and actuation of the AFW system, is 10 percent NRS for the CPSES, Unit 1 Δ76 SGs, and 7.5 percent NRS for the CPSES, Unit 2 D-5 SGs.

Unlike the licensing basis FLB analyses (Reference 44), the SPU FLB analyses are based upon the assumption that the pressurizer PORVs are available. This assumption is conservative with respect to the acceptance criterion, i.e., not reaching hot-leg saturation before the AFW system can remove all the stored and decay heat in the RCS, since the action of the PORVs would tend to limit RCS pressure and therefore the hot-leg saturation temperature. Thus, the lower hot-leg saturation temperature, relative to hot-leg temperature, is conservative. Otherwise, the PORVs do not perform a safety function. The resulting minimum margin to hot-leg saturation is 10 °F.

If the PORVs were not assumed to be available, the FLB would cause the RCS to pressurize to a higher level, and RCS overpressure protection would be provided by the pressurizer safety valves. The licensing basis analyses (Reference 44) predict that the calculated peak RCS pressures would be higher, without operation of the PORVs; but still within 110 percent of design pressure.

These cases demonstrate that RCS and MSS pressure will be limited to less than 110 percent of design, and that the AFW system capacity is adequate to remove stored and decay heat, such that the core will remain covered. Therefore, the NRC staff finds this acceptable.

Based upon the input parameters, assumptions, and modeling techniques described in SPULR Section 2.8.5.2.4, and in responses to RAIs (Reference 7), the NRC staff finds the CPSES, Unit 1 and CPSES, Unit 2 FLB transient simulations and the identification of the limiting cases

acceptable. The licensee provided reasonable assurance that all of the acceptance criteria continue to be met. The CPSES, Unit 1 and CPSES, Unit 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 NRC staff finds that the results of the CPSES, Unit 1 and CPSES, Unit 2 FLB analysis acceptable.

The NRC staff concludes that the licensee's analyses adequately account for operation of the licensee's plants at SPU conditions and were performed using acceptable analytical models. The NRC staff further concludes that the licensee demonstrated that the RPS and safety systems will continue to assure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a non-brittle manner, the probability of propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. The NRC staff concludes that the plant will continue to meet the regulatory requirements at SPU conditions with respect to the FLB events.

2.8.5.2.4.3 Conclusion

The 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 SPU 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 NRC staff concludes that the plant will continue to meet the requirements of GDC-27, GDC-28, GDC-31, and GDC-35 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to feedwater system pipe breaks.

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

2.8.5.3.1.1 Regulatory Evaluation

A decrease in 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 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 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 15.3.1-2 and other guidance is provided in Matrix 8 of RS-001 (Reference 1).

2.8.5.3.1.2 Technical Evaluation

For the loss of flow transients, the licensee analyzed three cases. The first case considered a loss of power to a single RCP. The second case considered a loss of power to all RCPs, and the third case considered a 5 Hertz per second frequency decay of all RCPs.

The selected cases, as evaluated in the following sections, demonstrate compliance with the acceptance criteria of a Condition II event (Reference 35), namely, that the sequence of events is terminated by reactor trip without exceeding DNBR or primary system pressure limits. The results of the analyzed cases also demonstrate that the sequence of events does not progress into a worse transient.

Based on the results provided by the licensee, the selected cases demonstrate compliance with applicable acceptance criteria over the range of possible coolant flow reduction transients. If two or three coolant pumps were to trip, the resultant transient would be terminated by the same available reactor trip signals. The flow reduction would be more rapid, but still bounded by the limiting case demonstrated, which was a complete loss of power to all RCPs. Therefore, the NRC staff finds that the three cases selected for analysis adequately demonstrate compliance with the NRC's acceptance criteria for postulated decreases in reactor coolant flow.

2.8.5.3.1.2.1 Partial Loss of Coolant Flow

A partial loss of coolant flow may be caused by a mechanical or electrical failure in an RCP motor, a fault in the power supply to the pump motor, or a pump motor trip caused by such anomalies as over-current or phase imbalance. The transient is characterized by a rapid increase in reactor coolant temperature. A partial loss of coolant flow may be terminated by low-flow sensed in 2/3 flow sensors on the RCL.

The licensee used the RETRAN computer code (Reference 23) to calculate the loop and core flow during the transient, the time of reactor trip based on RCP speed, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE computer code (Reference 38) was then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS flow from RETRAN. The event was analyzed using the RTDP (Reference 39) assuming initial reactor power, RCS pressure, and vessel temperature were at their nominal values for uprate conditions. Assumptions are made such that the core power was maximized during the initial part of the transient when the minimum DNBR was reached.

Acceptance criteria for this event include maintaining the DNBR above the SAL, and maintaining both primary and secondary pressures below 110 percent of the design pressure for each system. Linear heat generation is also demonstrated not to exceed the value at which fuel melt is predicted to occur.

The 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 operation under uprate conditions. The staff observed that the results of this transient sequence maintain significant margin to the applicable limits, and are less limiting than the results of the complete loss of coolant flow events. The licensee's analysis demonstrated that the reactor tripped on reactor coolant low flow. The staff concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed SPU. Therefore, the staff found the proposed SPU acceptable with respect to the partial loss of forced reactor coolant flow event.

2.8.5.3.1.2.2 Complete Loss of Coolant Flow

A complete loss of forced reactor coolant flow, an ANS Condition III event, may result from a simultaneous loss of electrical power supply or a reduction in power supply frequency to all RCPs. A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer and a subsequent increase in fuel temperature. Accompanying fuel damage could then result if SAFDLs are exceeded during the transient. The RPS is engaged to mitigate the transient. The licensee conservatively applied ANS Condition II acceptance criteria to the analysis of this event. Thus, the licensee demonstrated that the CHF was not exceeded, and pressure in the RCS and MSS remained below 110 percent of their respective design pressures. Specific review criteria are found in SRP Section 15.3.1-15.3.2.

The licensee analyzed this accident using the RTDP (Reference 39) along with the RETRAN computer code (Reference 23) to calculate the loop and core flows during the transient, the time of reactor trip, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE code (Reference 38) was then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN.

For the complete loss of flow event, the licensee analyzed two transient cases: (1) a loss of power to all pumps and (2) a frequency decay condition. The licensee indicated that the frequency decay case was tripped by the under-frequency reactor trip signal. The more limiting event with respect to DNB was the complete loss of flow under-voltage case. The VIPRE analysis for all scenarios confirmed that the minimum DNBR value of 1.90 (for the undervoltage case) was higher than the SAL value of 1.61. The transient plots provided indicated that peak

RCS pressures remained below the limits at all times, and the licensee confirmed that the peak MSS pressures remained below the respective limits at all times.

The 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 SPU acceptable with respect to the complete loss of reactor coolant flow.

2.8.5.3.1.3 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 NRC 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 NRC staff concludes that the plant will continue to meet the requirements of GDC-10, GDC-15, and GDC-26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the decrease in reactor coolant flow events.

2.8.5.3.2 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

2.8.5.3.2.1 Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of 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, RPS is 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 non-brittle manner and the probability of a rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 15.3.3-4 and other guidance is provided in Matrix 8 of RS-001 (Reference 1).

2.8.5.3.2.2 Technical Evaluation

The postulated LRA, an ANS Condition IV event, can result from an instantaneous seizure of the RCP rotor or the break of the RCP shaft.

The ANS Condition IV event acceptance criteria were applied as follows:

(1) RCS pressure should be below the designated limit,

(2) Coolable core geometry is ensured by showing that the peak cladding temperature (PCT) and maximum oxidation level for the hot spot are below 270 °F and 16 percent by weight, respectively, and

(3) Activity release is such that the calculated doses meet 10 CFR 100 guidelines. At CPSES, Units 1 and 2, this corresponds to a limiting amount of 10 percent of fuel rods in DNB.

Specific review criteria are found in SRP Section 15.3.3-4.

The licensee employed two primary computer codes to analyze this event. RETRAN (Reference 23) was used to calculate the loop and core flows during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE code (Reference 38), was then used to calculate the PCT using the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN.

The licensee analyzed a postulated locked rotor, and noted that the consequences of the LRA are very similar to those of an RCP shaft break. The locked rotor causes a more rapid, initial

reduction in the coolant flow, which results in a more challenging scenario with respect to DNB margin, peak pressure, and PCT. The RCP shaft break, however, would possibly leave the impeller free to spin in the reverse direction, which would ultimately reduce core flow when compared to the locked-rotor scenario. The licensee stated that the postulated LRA represents the most limiting combination of conditions for this class of accidents. The staff agrees with this approach, because the acceptance criteria for these postulated accidents are challenged early in the sequence of events, when the initial reduction in core flow caused by the locked rotor poses a more limiting scenario.

This postulated accident was analyzed twice. To evaluate peak RCS pressure and PCT, the licensee employed conservative assumptions designed to maximize RCS pressure and cladding temperature transients using the Standard Thermal Design Procedure (STDP). Unlike the RTDP, which analyzes events at nominal conditions and applies uncertainties in a statistical process, the STDP applies uncertainties to initial conditions, which result in a conservative analytical approach. The RTDP approach was used to evaluate the percentage of rods in DNB for confirmation that it was less than 10 percent, consistent with the radiological analysis.

The peak pressure and temperature analysis assumed initial core power, reactor coolant temperature, and pressure were at maximum values for full-power operation, with allowances for calibration and instrument errors, whereas the DNB analysis used initial conditions consistent with the RTDP approach.

The licensee conservatively took no credit for pressurizer PORVs, spray, or steam dumps. When operating, these systems would have the effect of lowering the expected peak pressure for this postulated accident. The licensee included a +2 percent setpoint tolerance for the pressurizer safety valves, plus a 1 percent set pressure shift due to water-filled pressurizer loop seals.

For the peak pressure and temperature analysis, the licensee assumed that the initial pressure was 2280 pounds per square inch (psi) to allow for initial condition uncertainties in the pressurizer pressure measurement and control channels. Results were presented at the point of RCS maximum pressure, which was the lower plenum of the RPV.

The results of the analysis indicated a peak hot spot cladding temperature of 1723.6 ºF, peak zirconium-water reaction of 0.22 percent, and a peak RCS pressure of 2574.5 psia. The total number of rods in DNB is predicted to be less than 10 percent, which is the analytic limit for the radiological analysis.

The 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 SPU. Therefore, the staff found the proposed SPU acceptable with respect to the postulated RCP locked rotor and shaft break accidents.

2.8.5.3.2.3 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 NRC 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 non brittle manner, the probability of propagating fracture of the RCPB is minimized, and adequate core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC-27, GDC-28, and GDC-31 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU 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

2.8.5.4.1.1 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 RPS 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 (Reference 1).

2.8.5.4.1.2 Technical Evaluation

The uncontrolled RCCA withdrawal from subcritical or low-power startup condition is an ANS Condition II 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 CPSES at the SPU conditions using the NRC-approved TWINKLE (Reference 45), FACTRAN (Reference 46), and VIPRE (Reference 38) computer codes. The results of the analysis showed that the minimum DNBR for the transient remains above the SAL value, and the peak fuel centerline temperature is 2304 °F, which is well below the minimum temperature where fuel melting would be expected at 4800 °F. The staff noted that the licensee did not analyze the peak reactor temperature or pressure for this transient. The licensee stated that the peak heat flux occurs at about 12 seconds, which is approximately 2 to 3 seconds after the reactor returns to significant power levels. The reactor trip is effective (start of rod motion) at 10.3 seconds (Reference 7). Therefore, the transient time of interest is only about the first 5 seconds after the return to power. This time is too short to result in any change in the reactor core inlet temperature. Although there would be a small increase in the RCS pressure, no credit is taken for this in the DNBR evaluation.

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 with acceptable results. The NRC staff also concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the Uncontrolled RCCA Withdrawal from a Subcritical condition event.

2.8.5.4.1.3 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 NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC 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 NRC staff concludes that the plant will continue to meet the requirements of GDC-10, GDC-20, and GDC-25 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the uncontrolled control rod assembly withdrawal from a subcritical or low-power startup condition.

2.8.5.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power

2.8.5.4.2.1 Regulatory Evaluation

An uncontrolled control rod assembly withdrawal at power (RWAP) 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 RPS 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 (Reference 1).

2.8.5.4.2.2 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, is affected by rated thermal power, 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 the CHF and that pressure in the RCS and MSS are maintained below 110 percent of the design pressures.

The licensee used RETRAN (Reference 23) to analyze the uncontrolled RCCA withdrawal at power event. This accident was analyzed with the RTDP which assumed the initial reactor

power, RCS pressure, and RCS temperature to be at their nominal values for conservatism (Reference 39). The uncontrolled RCCA withdrawal at power event analysis credits reactor trips from only the power-range high neutron flux and overtemperature delta T (OTΔT) trip signals. A series of cases were considered at initial power levels of 10, 60, and 100 percent of the NSSS power of 3628 MWt, with minimum reactivity feedback (i.e., a least negative or positive value of the moderator temperature coefficient of reactivity is assumed corresponding to the beginning of core life. A conservatively small value of the Doppler coefficient is assumed), and maximum reactivity feedback (i.e., a conservatively large positive moderator density coefficient and a large negative Doppler coefficient are assumed), 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 (45 inches/minute, which corresponds to 72 steps/minute). These coefficient values were determined from operating experience from CPSES and other plants, and are confirmed via the cycle-specific reload process (Reference 7). The range of cases selected was consistent with the SRP Section 15.4.2. For the slower reactivity insertion rates, the OTN16 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.

The NRC staff noticed that two cases for the minimum and maximum reactivity, stated in the SPULR, were analyzed. During the staff's review, the results of the maximum reactivity feedback case were not included in the review. The licensee provided the results in an attached revision to Section 2.8.5.4.2. This section was revised to address some isolated issues related to the corresponding analysis (Reference 7). The revised analysis affected results that were presented in Table 2.8.5.0-1, Table 2.8.5.4.2-1, and Table 2.8.5.4.5-1 (Boron Dilution) of the SPULR. The licensee included these revised tables in the revised attachments. The staff reviewed these revisions and found them to be acceptable. Both cases analyzed show the minimum DNBR was greater than the SAL value of 1.61.

Regarding the potential for RCS overpressurization during a rod withdrawal error at power, the SPULR states:

> "… a conservative generic evaluation that is applicable to [CPSES] has shown that the positive flux rate and high-pressurizer pressure functions provide a timely reactor trip that precludes RCS overpressurization in instances where the power range high neutron flux of the OTN-16 trip occur too late to provide the necessary protection. This evaluation confirms that the RCS pressure limit is met."

This "generic evaluation" is generic in the sense that it is designed to be representative of all Westinghouse 4-loop PWR plants. However, the NRC staff has not reviewed and approved this evaluation on a generic basis. Therefore, the NRC staff requested that the licensee provide additional information about this analysis to confirm its continued applicability to the uprated conditions at CPSES.

The licensee provided this information in a letter dated May 14, 2008 (Reference 15). This letter contains, *inter alia*, a qualitative description of the low-power rod withdrawal at power event sequence, an explanation detailing why the low-power transient sequence presents the limiting

potential for RCS overpressurization, and a quantitative description of the generic analysis parameters and comparison to conditions at CPSES.

Of most significant concern to the NRC staff, the nominal power level assumed in the generic analysis was 20 MWt less than CPSES's proposed SPU power level. The NRC staff was concerned that this non-bounded power level could potentially result in a rod withdrawal at power sequence that pressurizes at CPSES more severely than predicted by the generic analysis.

The NRC staff reviewed the conditions of the generic analysis as compared to the parameters requested for uprate operation at CPSES. Although the generic analysis reflects a power level 20 MWt lower than requested for CPSES, the initial vessel average temperature is approximately 20 °F higher for the generic analysis. This would increase the liquid expansion in the generic analysis as compared to CPSES, such that the pressurization would be more severe in the generic analysis. Also, the initial pressurizer level from the generic analysis is higher than at CPSES, so that the analyzed pressurizer has less vapor volume to absorb liquid expansion. The analyzed pressurizer safety valve setpoint is higher than those at CPSES by approximately 80 psi, which would result in the safety valves at CPSES being more effective at mitigating the overpressure effects of this transient when compared to the generic analysis. Finally, the analyzed positive flux rate trip setpoint and time delay are higher than at CPSES, such that this transient would terminate faster at CPSES than predicted by the generic analysis.

In its review of the licensee's supplemental information, the NRC staff considered not only these assumptions, but also remaining assumptions employed in the generic analysis. The remaining assumptions contain sufficient conservatism relative to the CPSES, Units 1 and 2 plant design that the NRC staff is reasonably assured that the licensee has demonstrated that, at uprated conditions, the low-power RWAP transient does not threaten to overpressurize the primary system. The transient is terminated by the positive flux rate trip, and adequately mitigated by the relief capacity of the pressurizer safety valves.

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 applicable regulatory requirements following implementation of the proposed SPU. Therefore, the staff found the proposed SPU acceptable with respect to the Uncontrolled RCCA Withdrawal at Power event.

2.8.5.4.2.3 Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control RWAP 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 NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC 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 NRC staff concludes that the plant will continue to meet the requirements of GDC-10, GDC-20, and GDC-25 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the uncontrolled control RWAP.

2.8.5.4.3 Control Rod Misoperation

2.8.5.4.3.1 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 (Reference 1).

2.8.5.4.3.2 Technical Evaluation

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

- One or more dropped RCCAs from the same group
- A dropped RCCA bank
- Statically misaligned RCCA

The withdrawal of a single RCCA is an ANS Condition III event.

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 NRC-approved topical report WCAP-11394 (Reference 47). The generic dropped RCCA statepoints are evaluated in each cycle as part of the reload SE process in order to demonstrate that the applicable DNB design basis is satisfied.

For this analysis, input parameters that are important for any time in cycle are initial power level and distribution, initial rod configuration, reactivity addition rate, moderator temperature, fuel temperature, and void reactivity coefficients. The licensee considered these parameters and the calculations for the DNB and peaking factor limit included uncertainty that bounded the plant's power level and reactor coolant conditions (i.e., moderator temperature, pressure, and flow). Also, the event analysis included conservative rod configuration and transient rod movement assumptions that are designed to generate limiting radial and axial power conditions and induce the maximum reactivity insertion possible for each accident scenario. Conservative reactivity coefficient values are assumed to be constant for the duration of each transient.

From review of the analysis, the staff noted that only control bank D was evaluated. The licensee responded by stating that during operation within the limiting condition for operation defined by the plant TSs 3.1.5 and 3.1.6, control bank D is allowed to be inserted more deeply into the core than the other control banks (the shutdown banks are required to be fully withdrawn) (Reference 7). As such, the largest reactivity effects (and thus, the highest local peaking factors) due to one RCCA being fully withdrawn at high reactor power levels are limited to an RCCA from control bank D.

The NRC staff agreed with the approach for the RCCA misoperation events in the context of the CPSES SPU. The staff concluded that for all cases of any single RCCA fully inserted, or bank D inserted to the rod insertion limit and any single RCCA in that bank fully withdrawn, the minimum DNBR remains above the limit value for CPSES, Units 1 and 2. Therefore, the DNB design criterion is met and the RCCA misalignments do not result in core damage given implementation of the SPU. For the case of the accidental withdrawal of a single RCCA, with the reactor in the automatic or manual control mode and initially operating at full power with bank D at the insertion limit, an upper bound of the number of fuel rods experiencing DNB is 5 percent of the total number of fuel rods in the core for CPSES, Units 1 and 2, which meets the DNB design criterion for a Condition III event. Therefore, the staff agreed the licensing basis acceptance criteria continue to be met and found the RCCA misalignment evaluation acceptable.

2.8.5.4.3.3 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 NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models.

The NRC 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 NRC staff concludes that the plant will

continue to meet the requirements of GDC-10, GDC-20, and GDC-25 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to control rod misoperation events.

2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature

CPSES, Units 1 and 2 TSs prohibit power operation with less than all four 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. The staff finds that this event need not be analyzed to implement the proposed SPU.

2.8.5.4.5 Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant

2.8.5.4.5.1 Regulatory Evaluation

Unborated water can be added to the RCS, via the CVCS. This may happen inadvertently because of operator error or CVCS malfunction, and cause an unwanted increase in reactivity and a decrease in SDM. The operator should stop this unplanned dilution before the SDM 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 (Reference 1).

SRP Section 15.4.6 stipulates that boron dilution events be considered for all modes of operation. Typically, licensees show acceptable results for this transient by demonstrating that 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. Consistent with the typical practice, and with the guidance contained in the SRP, the licensee stated that the specific acceptance criterion applied for these events is that adequate operator action time is available prior to a complete loss of SDM. For boron dilution events in Modes 1 through 5, there must be at least 15 minutes from operator notification until SDM is lost.

2.8.5.4.5.2 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 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.

For at power and start-up conditions, Modes 1 and 2, the dilution accident erodes the SDM made available through reactor trip. For shutdown mode initial conditions, Modes 3, 4, 5, and 6, the dilution accident erodes the SDM inherent in the borated RCS inventory and that which may be provided by control rods (control and shutdown banks) made available through reactor trip.

Analysis of this event involved a calculation of the time required for a constant dilution rate to lose available SDM. The key parameters of interest were the dilution flow, the active RCS volume, the initial boron concentration and the critical boron concentration.

Boron Dilution Parameters

	Initial Boron Concentration (ppm)	Critical Boron Concentration (ppm)	Dilution Flow (gpm)	Dilution Volume (ft^3)
Mode 1	2100	1800	157.5	CPSES, Unit 1: 11,071.5 CPSES, Unit 2: 9,761.9
Mode 2				
Mode 3	Initial and critical boron concentrations for Modes 3-5 are determined based on the 15-minute response time from operator notification.		157.5	CPSES, Unit 1: 9,903.7 CPSES, Unit 2: 8,594.0
Mode 4				
Mode 5				Mode 5 Drained: 4,513 CPSES, Units 1 & 2

The licensee provided the parameters for each mode except Mode 6. The licensee stated that TS 3.9.2 requires each valve used to isolate unborated water sources to be secured in the closed position in Mode 6 (Reference 7). This requirement effectively precludes an inadvertent boron dilution. The staff agrees that an analysis of boron dilution during Mode 6 is therefore unwarranted.

During its review, the staff observed that dilution volumes and initial boron concentrations presented for the power uprate analyses were different from those presented in the current licensing basis. For instance, the current licensing basis assumes, for operating modes, a 500 ppm dilution to reach critical boron concentration. This difference in assumptions results in less available time to terminate the boron dilution in the uprate analyses, but still remains within the 15 minute SRP acceptance criterion. The licensee stated that the dilution volumes assumed in the analyses for the SPU also include correction of a Westinghouse-identified generic discrepancy associated with the RCS volume contained in the RCS loop stop valves, and that the SPU analyses have been performed with conservative assumptions to bound the discrepancy (Reference 41).

The following table presents the results of the licensee's boron dilution analyses for Modes 1 and 2, which shows that the results are acceptable.

Boron Dilution Results

Unit 1 - Condition	Uprate Analysis	Limit
Mode 1 Manual Rod Control	54.6 Minutes	15 Minutes
Mode 1 Auto Rod Control	56.5 Minutes	15 Minutes
Mode 2	59.5 Minutes	15 Minutes
Unit 2 - Condition	**Uprate Analysis**	**Limit**
Mode 1 Manual Rod Control	48.0 Minutes	15 Minutes
Mode 1 Auto Rod Control	49.8 Minutes	15 Minutes
Mode 2	52.5 Minutes	15 Minutes

As can be seen from the above table, the licensee has sufficient margin for its Modes 1 and 2 dilution events. For Modes 3-5, the available time from operator notification is 15 minutes to

terminate the boron dilution. Using this assumption as a basis, the licensee analyzes the boron dilution event to generate minimum SDM requirements as a function of the critical boron concentration. The staff finds this approach acceptable because it preserves the 15-minute operator termination time limit.

The staff reviewed the assumptions that the licensee employed for the analyses, and confirmed that, to the extent that the licensing basis does not change for the uprate, the analytical assumptions remain conservatively bounding of or consistent with the licensing basis. The analyzed reductions in margin between initial and critical boron concentration are reflected in the analysis results, which remain acceptable. Therefore, the staff finds that the licensee's analysis of boron dilution events acceptable for the proposed SPU.

2.8.5.4.5.3 Conclusion

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 semi-analytic approach, which is consistent with the licensee's current licensing basis, has adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical models. The NRC 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 NRC staff concludes that the plant will continue to meet the requirements of GDC-10, GDC-15, and GDC-26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU 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

2.8.5.4.6.1 Regulatory Evaluation

Control rod ejection accidents (CREAs) cause a rapid positive reactivity insertion that could, together with an adverse core power distribution, lead to localized fuel rod damage. The NRC staff evaluates the consequences of a CREA 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 NRC staff's review covered

(1) Initial conditions,

(2) Rod patterns and worths,

(3) Scram worth as a function of time,

(4) Reactivity coefficients,

(5) The analytical model used for analyses,

(6) Core parameters that affect the peak reactor pressure or the probability of fuel rod failure, and

(7) 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 (Reference 1).

2.8.5.4.6.2 Technical Evaluation

CREAs 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 cycle (BOC) and end of cycle (EOC). Since the RCCA ejection transient is a rapid transient, initial plant conditions, such as power level, pressure, flow, and temperature are not significant.

The licensee applied acceptance criteria to its analysis based on experimental testing and on conclusions drawn in WCAP-7588 (Reference 48). Analytical limits on stored energy for both previously irradiated and unirradiated fuel are 200 calories per gram (cal/g), and fuel melt must remain less than 10 percent of the pellet volume at the hot spot. Acceptance for pressure surges is based on not exceeding faulted-condition stress limits, and the licensee provided a generic disposition for this criterion. The staff observes that these acceptance criteria are more rigorous than those contained in RG 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors" (Reference 16).

The calculation of the RCCA ejection accidents is performed using a two-stage process. An average core calculation is performed using the TWINKLE spatial neutron kinetics code (Reference 45), followed by a hot spot analysis using FACTRAN (Reference 46).

The CREA analyses for CPSES, Units 1 and 2 were performed assuming the SPU power level, at beginning of license (BOL) and EOL. The peak hot spot average fuel pellet enthalpy at full power reached 161.6 cal/g and 157.5 cal/g (BOL and EOL). The peak fuel centerline temperature reached the BOL and EOL (4900 °F and 4800 °F, respectively) melting temperatures for the full power analyses however, for both cases, fuel melting remained well below the limiting criterion of 10 percent of total pellet volume at the hot spot. The peak hot spot average fuel pellet enthalpy at zero power reached 114.3 cal/g and 138.9 cal/g (BOL and EOL). The peak fuel centerline temperature never reached the BOL or EOL melting temperatures for the zero power analyses therefore no fuel melting occurred in either case. The staff also reviewed the cladding oxidation results and found them acceptable (Reference 7).

As a result of a fuel failure during a test at the CABRI reactor in France in 1993, and one in 1994 at the NSRR test reactor in Japan, 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 less than 100-cal/g.

The 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 (GWD/MTU) 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. At CPSES uprated conditions, the severity of the RCCA ejection accidents does not exceed the worst-case analysis such that the generic disposition remains bounding and applicable.

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 staff finds that the results and conclusions of the analyses performed for the CREA are acceptable for operation at the proposed SPU power level of 3612 MWt at CPSES, Units 1 and 2.

In its review of the licensee's power uprate proposal, the NRC staff considered also guidance contained in the 2007 revision to the SRP, and in proposed interim reactivity-initiated accident acceptance criteria discussed in an enclosure to a memorandum from Ralph Landry, Chief, Nuclear Performance and Code Review Branch, NRC, to Thomas Martin, Director, Division of Safety Systems, NRC, dated January 19, 2007 (Reference 49).

The enclosure to the January 19, 2007, memorandum proposed new limits for zero-power cases of enthalpy deposition less than 150 cal/g and a pellet-clad metal interaction limit of 4 percent of the clad thickness. The NRC staff confirmed that the licensee's analytic results also demonstrate compliance with these acceptance criteria.

The enclosure proposed thermal-hydraulic acceptance criteria for low- and full-power analyses, which the licensee satisfied by using RETRAN to calculate the number of rods in DNB and confirm that it is less than the 10 percent limit indicated by the dose analysis. The generic evaluation in Reference 48 demonstrates that system pressurization associated with this postulated accident would not exceed limits for the faulted condition of the RCS pressure boundary. Hence, the licensee's analysis demonstrates compliance with the NRC staff's more recently published acceptance criteria for the reactivity initiated accident (Reference 49).

2.8.5.4.6.3 Conclusion

The NRC staff has reviewed the licensee's analyses of the rod ejection accident (REA) 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 NRC 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 NRC staff concludes that the plant will continue to meet the requirements of GDC-28 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed uprate acceptable with respect to the REA.

2.8.5.5 Inadvertent Operation of ECCS and CVCS Malfunction that Increases Reactor Coolant Inventory

2.8.5.5.1 Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the boron concentration and temperature of the injected water and the response of the automatic control systems, a power level increase may result and, without adequate controls, could lead to fuel damage or overpressurization of the RCS. Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events.

The 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 Section 15.5.1-2 and other guidance is provided in Matrix 8 of RS-001 (Reference 1), and RIS-2005-29 (Reference 50).

2.8.5.5.2 Technical Evaluation

2.8.5.5.2.1 Inadvertent Operation of ECCS

An inadvertent actuation of the ECCS at power event, an AOO, could be caused by operator error or a false electrical actuating signal. The ECCS uses the charging pumps to pump borated water from the RWST into the cold leg of each RCS loop. The safety-injection pumps are also actuated; but they are not capable of delivering flow to the RCS when the RCS is at nominal pressure.

The inadvertent ECCS actuation at-power event will continue to add water to the RCS until the ECCS is shut off by the operator. This event could develop into a more serious event, e.g., a SBLOCA, if the pressurizer fills and a pressurizer relief or safety valve opens and fails to reseat (Reference 50). This would be a violation of the ANS Condition II acceptance criterion that prohibits escalation of a Condition II event to a more serious event.

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 the ECCS before the pressurizer can become water-solid. The possibility that a pressurizer relief or safety valve fails to reseat is thereby eliminated, since an open pressurizer relief or safety valve would not have to discharge any water.

The inadvertent ECCS at power event was analyzed using the RETRAN computer code (Reference 23). The RETRAN computer code is a digital computer code, used to simulate transient behavior in light water reactor systems. The code includes a one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, an ECCS model, and a non-equilibrium pressurizer model. The code computes pertinent plant variables including temperatures, pressures and power level.

Protection for the inadvertent ECCS at power event requires manual actions. The licensee's analysis assumes that the operators open at least three of the four SG ARVs within 7 minutes and 30 seconds after the ECCS is inadvertently actuated. Steam dumping through the SG ARVs is used to control RCS average temperature to the no-load value of 557 °F. The cooling effect tends to shrink the RCS water volume and retard the rate of increase in pressurizer water level. In this way, the operators gain the time they need to shut off the ECCS before the pressurizer can become water-solid. The operators terminate the event by shutting down the ECCS no later than 13 minutes after it begins. The maximum pressurizer water volume, 178 cubic feet, remains less than its total volume, 1800 cubic feet.

The licensee has verified that the assumed operator response times are reasonable by means of a simulator exercise (Reference 7). The operators were able to take control of the RCS average temperature well within the assumed 7.5 minutes, and to secure ECCS at about

10 minutes. The operator response times, will be periodically reviewed against those assumed in the accident analysis and, based on simulator observations, re-validated as necessary.

The staff agrees with the licensee's analytical approach, assumptions, and results. The staff also notes that the pressurizer total volume, 1800 cubic feet, would be about 50 cubic feet greater if the surge-line volume were to be included. Hence, the analysis is based on a conservative pressurizer volume of 1800 cubic feet.

2.8.5.5.2.2 CVCS Malfunction that Increases RCS Inventory

The CVCS malfunction that increases RCS inventory is a Condition II event that is evaluated for the effects of adding water inventory to the RCS. This event could be caused by operator error or a spurious actuating signal. In this case, the fault is assumed to be a spurious, low-pressurizer water level signal, which would cause charging flow to increase to its maximum rate. If the charging system were under automatic control, and the pressurizer level channel that is used for charging control were to fail in the low direction, then the maximum amount of charging flow to be delivered to the RCS, letdown flow would be isolated, and a low-level alarm would be issued. If a second pressurizer level were to fail in an as-is condition or a low condition (as the worst single failure), then reactor trip, on two-out-of-three high-pressurizer level channels, would be defeated. Makeup water, of a boron concentration that is equal to the boron concentration in the RCS, is added until the operator acts to terminate the flow. If the charging flow is ended before the pressurizer becomes water-solid, then the possibility of a PORV opening, discharging water, and failing to reseat properly is eliminated.

Either event, the inadvertent actuation of the ECCS at power or the CVCS malfunction, can cause the pressurizer to become water-solid, and result in water discharge from the pressurizer; but in the CVCS malfunction, the time to fill the pressurizer is longer, due to a lower charging flow rate, from one charging pump. The effect of a reactor trip, if one occurs during the transient, would temporarily reduce pressurizer water level. Assuming the operators are alerted to an abnormal condition at the same time, from an ECCS actuation signal or a low-level alarm, then there would be more time available for operator action during a CVCS malfunction than for an inadvertent actuation of the ECCS at power. The CVCS malfunction event, therefore, is bounded by the inadvertent actuation of the ECCS at power event.

The staff accepts the licensee's determination that the CVCS malfunction that increases reactor coolant inventory is bounded by the inadvertent actuation of the ECCS event.

The staff reviewed the licensee's evaluation of the CVCS malfunction event and agrees that the licensee's conclusion is justified. The staff agrees, too, that the pressurizer would not become water solid before the operator can terminate the transient, by shutting off the charging flow, and thereby prevent this event from escalating to a more serious event. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed SPU with respect to the CVCS malfunction transient.

2.8.5.5.3 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 acceptable analytical

models. The NRC staff also reviewed the licensee's evaluation of the CVCS malfunction that increases RCS inventory and concluded that the licensee's evaluation was performed using an acceptable operational basis. The NRC staff also concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the inadvertent ECCS actuation at-power and the CVCS malfunction that increases RCS inventory events.

2.8.5.6 Decreases in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of Pressurizer Pressure Relief Valve

2.8.5.6.1.1 Regulatory Evaluation

The inadvertent opening of a pressure relief valve (PRV) 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 the 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 (Reference 1).

2.8.5.6.1.2 Technical Evaluation

An accidental depressurization of the RCS could occur as a result of an inadvertent opening of a PRV. 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 flow rate of a relief valve and will allow a much more rapid depressurization upon opening. The reactor may be tripped on low-pressurizer pressure, or, as indicated by the licensee, on overtemperature N-16.

Analysis of the accidental depressurization of the RCS is required to meet the ANS Condition II criteria. The key acceptance criterion is demonstration that the DNBR is not reduced below the SAL at any time during the transient. Additionally, RCS and MSS pressures should be maintained within their design limits. As this is a depressurization event, pressure limits are not challenged.

The licensee analyzed this event using the RETRAN computer code (Reference 23) to simulate neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SG, and SG safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. The licensee performed the analysis in accordance with the RTDP to calculate the minimum DNBR during the transient. Assumptions used for the analysis included conservative reactivity coefficients to reduce negative reactivity effects, or to maximize any power increase, associated with the transient.

The licensee's analysis indicated that the reactor tripped on OTΔT, and resulted in a minimum DNBR of 1.923/1.921 (CPSES, Unit 1/CPSES, Unit 2), in comparison to the DNBR SAL of 1.61.

The NRC staff reviewed the licensee's demonstration analyses of inadvertent pressurizer PRV opening, performed in accordance with the NRC-approved RETRAN transient analysis methodology using the RTDP (Reference 39). 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 and secondary pressure limits are not challenged. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff found the proposed SPU acceptable with respect to the accidental depressurization of the RCS event.

2.8.5.6.1.3 Conclusion

The NRC staff has reviewed the licensee's analysis of the inadvertent opening of a pressurizer PRV and concludes that the licensee's analysis has adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical models. The NRC 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 NRC staff concludes that the plant will continue to meet the requirements of GDC-10, GDC-15, and GDC-26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the inadvertent opening of a pressurizer PRV event.

2.8.5.6.2 Steam Generator Tube Rupture

2.8.5.6.2.1 Regulatory Evaluation

A 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 ARVs. 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 NRC 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 100 is satisfied with respect to radiological consequences, which are discussed in Section 2.9 of this SE, and

(2) Confirm that the faulted SG does not experience an overfill. Preventing overfill is necessary in order to prevent the failure of the 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 (Reference 1).

2.8.5.6.2.2 Technical Evaluation

A SGTR accident, an ANS Condition IV event, will transfer radioactive reactor coolant to the shell side of the SG as a result of the ruptured tube, and ultimately to the atmosphere. Therefore, the SGTR analyses for the proposed SPU 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 15.6.3; this review

considers the thermal-hydraulic modeling of the accident, and not the radiological consequences.

The SGTR analyses assume the complete severance of one SG tube. Other assumptions are a NSSS power level of 3628 MWt plus 0.6 percent calorimetric uncertainty and a full-power T_{avg} operating range of 574.2 °F to 589.2 °F. The analyses also consider up to 10 percent SG tube plugging, and a main feedwater temperature range from 390.0 °F to 450.3 °F.

The licensee analyzed the SGTR using the NRC-approved RETRAN program, modified as described in Reference 51. The modifications supported the explicit modeling of the CPSES EOPs, and were based on direct simulator observation of the SGTR sequence of events. The operator actions currently modeled in the postulated SGTR are based on the operator actions assumed in the current licensing basis.

Two separate SGTR analyses were completed; one was performed to demonstrate margin-to-overfill, in order to demonstrate that the sequence of events does not result in overfilling the faulted SG. Because the assumptions used in this analysis may not result in the most significant radiological release, a separate analysis was performed using assumptions to maximize the mass release through the ruptured SG tube.

The licensee performed sensitivity studies to determine the most limiting set of analysis conditions. In both analysis cases, the studies considered RCS initial average temperature, SG tube plugging, initial secondary water mass, feedwater temperature, and auxiliary feed flow.

For the margin-to-overfill cases, initial water mass in the SG was assumed to be that which corresponded to 77 percent of narrow-range level for Unit 1, and to 82 percent of narrow-range level for Unit 2. A turbine runback was simulated, but not assumed to delay the reactor trip, as an earlier trip results in greater atmospheric steam releases from the SGs. The maximum auxiliary feed flow was assumed, since it was determined to provide the lowest margin to overfill.

For the mass release cases, the initial SG water mass corresponding to 57 percent on the narrow-range level was modeled, as it was shown to increase predicted offsite doses. A turbine runback was not assumed. As a result, the reactor tripped earlier, which resulted in greater atmospheric steam releases from all SGs. Minimum auxiliary feed flow was modeled because it provided the most conservative mass release data.

The SGTR analysis credits certain operator actions. At CPSES, operators are credited to identify the ruptured SG and control excessive AFW flow to the ruptured SG. Operators are also credited to isolate steam flow from the ruptured SG. The operators must also cool down the RCS by dumping steam from the intact SGs. RCS depressurization is required, following cooldown, to minimize break flow and restore pressurizer level. Finally, operator action is credited to terminate safety injection to prevent re-pressurization of the RCS and terminate primary-to-secondary flow.

The NRC staff has reviewed the licensee's analyses of the SGTR event. The operator actions credited in the analysis are based on explicit operator actions modeled using the methodology in WCAP-10698 (Reference 52). The accident was modeled using an approved method,

RETRAN (Reference 23), and the input conditions were demonstrated to be conservative by sensitivity study. On the basis of the items discussed above, the staff concludes that the thermal-hydraulic analysis of the SGTR accident is acceptable, and that there is reasonable assurance that the faulted SG will not overfill.

At CPSES, Unit 1, this conclusion is predicated on an HFP operating temperature no less than 580 °F, because at temperatures below this value, the licensee's analyses predicted that the SG would overfill. The SE for WCAP-10698 contains a discussion of the acceptability of predictions that an SG may overfill. While the staff did not evaluate the potential consequences of SG overfill, the staff acknowledged that the most likely consequence would be the failure of the MSSVs to reseat after passing water. Because the temperature range below 580 °F represents reduced temperatures used at the EOC, and because the staff previously acknowledged this potential in WCAP-10698, and finally, because the dose consequence analysis predicts a larger mass release than the margin-to-overfill analysis, the NRC staff accepts the licensee's margin-to-overfill analysis for CPSES, Unit 1.

For CPSES, Unit 2, the licensee demonstrated adequate margin-to-overfill for the entire temperature range. The staff finds, therefore, that the proposed SPU is acceptable with respect to the SGTR event.

2.8.5.6.2.3 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 CPSES at the proposed uprated power level and was performed using acceptable analytical methods and approved computer codes. The NRC staff further concludes that the assumptions used in this analysis are conservative and the event does not result in an overfill of the faulted SG. Therefore, the NRC staff finds that the proposed SPU is acceptable with respect to the SGTR event.

2.8.5.6.3 Emergency Core Cooling System and Loss-of-Coolant Accidents

2.8.5.6.3.1 Regulatory Evaluation

LOCAs are postulated accidents that would result in the loss of reactor coolant from piping breaks in the 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,

(5) Calculations of PCT, 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, 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) Appendix K to 10 CFR Part 50, 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 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 (Reference 1).

2.8.5.6.3.2 Technical Evaluation

By letter dated April 10, 2007, the CPSES, Units 1 and 2 licensee requested to implement new analytic methods to analyze loss of coolant accidents at the uprated power level (Reference 53). Based on its detailed review of the licensee's (1) selection of analytic techniques, (2) implementation of analytic techniques, and (3) results of analysis, the staff concluded that the licensee could use the referenced methods to analyze LOCAs and demonstrate compliance with the requirements of 10 CFR 50.46 at the uprated power level (Reference 27). Reference 27 contains the staff's evaluation; the NRC staff summarizes in the following section the methods, their implementation, and the analytic results. The specific evaluations address the acceptance criteria contained in 10 CFR 50.46(b)(1) through (b)(3), and (b)(5) . By demonstrating compliance with these criteria, regarding PCT, local and core-wide oxidation, and

long-term cooling capability, the licensee adequately demonstrates compliance with 10 CFR 50.46(b)(4), which requires that the core remain in a coolable geometry.

2.8.5.6.3.2.1 Large Break LOCA

Large-break loss-of-coolant accident (LBLOCA) analyses supporting the proposed SPU were performed by the licensee using the NRC-approved Automated Statistical Treatment of Uncertainty Method (ASTRUM) best-estimate LBLOCA (BE-LBLOCA) methodology (Reference 54). The licensee's method was approved by the NRC for implementation at CPSES, Units 1 and 2 at uprated conditions by Amendment 144 to CPSES, Units 1 and 2 Facility Operating Licenses (Reference 27). The NRC staff reviewed the analysis to confirm that the analysis results were acceptable for the proposed SPU.

The purpose of the licensee's analysis was to demonstrate conformance with the 10 CFR 50.46 requirements at the planned power uprate conditions with the ASTRUM method. Important input assumptions, as well as analytical models and analysis methodology for the BE-LBLOCA were provided. Analysis results were also provided, which showed that no design or regulatory limit related to the BE-LBLOCA would be exceeded at the conditions analyzed.

The licensee stated in its August 28, 2007, submittal (Reference 3), that both the licensee and its vendor, Westinghouse Electric Company LLC, have ongoing processes which assure that LOCA analyses input values conservatively bound the as-operated plant values for those parameters. The NRC staff finds that this statement, along with the generic acceptance of ASTRUM methodology, provides reasonable assurance that ASTRUM and its BE-LBLOCA analysis apply to CPSES, Units 1 and 2 at the proposed uprated power levels.

The licensee provided results of the CPSES, Units 1 and 2 BE-LBLOCA analysis in the SPULR, assuming that the plant is operating at 3612 MWt, in accordance with the statistical best-estimate approach. The licensee correctly assumed a LOOP. The results for calculated PCTs, the maximum local cladding oxidations, and the maximum core-wide cladding oxidations are repeated in the following table, based on the limiting results obtained in CPSES, Unit 2:

Parameter	CPSES, Unit 2 Result	10 CFR 50.46 Limit
Limiting Break Size/Location	DEG/PD	N/A
Cladding Material	ZIRLO	(Cylindrical) Zircaloy or ZIRLO
Peak Cladding Temperature	1632 °F	2200 °F
Maximum Local Oxidation	0.71 percent	17.0 percent
Maximum Total Core-Wide Oxidation	Negligible	1.00 percent

These results demonstrate acceptable compliance with 10 CFR 50.46(b)(1) through (b)(3). The results are discussed further in Reference (Reference 27).

The NRC staff reviewed the CQD Methodology (Reference 55) and the ASTRUM methodology (Reference 54), and confirmed that, in addition to the limiting double-ended guillotine rupture, the method also considers slot breaks in the RCS cold leg. On this basis, the NRC staff finds the licensee's conclusion that the CPSES, Units 1 and 2 PCT-limiting transient is a

double-ended cold leg guillotine break acceptable, because uncertainties related to break type and size were included in the modeling approach.

The NRC staff concluded that the CPSES, Units 1 and 2 LBLOCA analysis considers downcomer boiling, as WCOBRA/TRAC properly models the effects of downcomer boiling in the transient calculation. The technical evaluation report accompanying the NRC staff's approval of the CQD methodology notes that Westinghouse employs conservative assumptions regarding downcomer and upper plenum entrainment, resulting in conservative PCT assumptions. These methods are also employed in the ASTRUM methodology, and the staff therefore agrees with the licensee's statement, and finds that the licensee has appropriately considered downcomer boiling in its analyses.

Based on its review of the licensee's application of the ASTRUM BE-LBLOCA methodology, the NRC staff concluded that the Westinghouse BE LBLOCA methodology is acceptable for use for CPSES, Units 1 and 2 in demonstrating compliance with the requirements of 10 CFR 50.46(b)(1) through (b)(3), operating at the proposed uprated conditions. The staff's conclusion was based on the fact that the CPSES, Units 1 and 2 analysis was conducted within the conditions and limitations, and supporting technical basis, of the NRC-approved Westinghouse BE LBLOCA methodology.

2.8.5.6.3.2.2 Small Break LOCA

The SBLOCA includes all postulated pipe ruptures with a total cross-sectional area less than 1.0 square foot. The SBLOCAs analyzed are for those breaks beyond the capability of a single charging pump, resulting in the actuation of the ECCS. The analysis was performed to demonstrate conformance with the 10 CFR 50.46 requirements for the uprated conditions associated with CPSES, Units 1 and 2.

The licensee received approval by the NRC to implement the NOTRUMP-EM as described in WCAP-10054-P-A, WCAP-10054-P-A, Addendum 2, and WCAP-10079-P-A (Reference 56), at 100.6 percent of the SPU power level, by Amendment 144 to both CPSES units (Reference 27). In consideration of the proposed SPU, the NRC staff reviewed the results to confirm that the licensee complies with the 10 CFR 50.46 requirements at the uprated power level; however, the acceptability of the method and the licensee's implementation of the method, including necessary modeling assumptions, at the SPU power level, are evaluated in Reference 27.

The licensee considered a spectrum of cold-leg break sizes that included equivalent diameters of 2, 3, 4, and 6 inches and an accumulator line break of 8.75 inches. At both units, the licensee identified the 4-inch break to be the most limiting. The 2-, 6-, and 8.75-inch breaks resulted in no core uncovery, and thus PCTs were not calculated for these breaks. Intermediate break sizes were not considered because the evaluated spectrum demonstrated significant margin to the 2200 ºF limit set forth by 10 CFR 50.46.

The licensee calculated a PCT of 1013 ºF for CPSES, Unit 1 and 1209 ºF for CPSES, Unit 2. The sum of pre-transient and transient oxidation remains below 17 percent at all times in life and the average oxidation is negligible for both units. The licensee's limiting results (which occur in CPSES, Unit 2) for the calculated PCT, the maximum local oxidation for cladding, and

the core wide oxidation for cladding are summarized in the following table, along with the acceptance criteria of 10 CFR 50.46(b).

Parameter	NOTRUMP Results	10 CFR 40.46 Limits
Limiting Break Size	4-inch	N/A
Peak Clad Temperature	1209 ºF	2200 ºF
Maximum Local Oxidation	0.05 percent	17.0 percent
Maximum Total Core-Wide Oxidation (All Fuel)	Negligible	1.0 percent

The NRC staff reviewed the licensee's demonstration evaluations of the ECCS during a SBLOCA, performed in accordance with the NOTRUMP SBLOCA methodology, for CPSES, Units 1 and 2 operating at the proposed, uprated power level of 3612 MWt. These specific analyses were performed to demonstrate the suitability of the NOTRUMP methodology for application to the CPSES units. The NRC staff concludes that the licensee has acceptably demonstrated, at the uprated power level, compliance with 10 CFR 50.46 (b)(1) through (b)(3).

2.8.5.6.3.2.3 Post-LOCA Long-Term Cooling and Sub-Criticality

To support its methods transition and proposed SPU, the licensee performed calculations to demonstrate post-LOCA sub-criticality and acceptable long-term cooling.

The post-LOCA sub-criticality calculations were performed to demonstrate compliance, in part, with 10 CFR 50.46(b)(5) , which requires a demonstration of acceptable long-term cooling capability. The sub-criticality calculation demonstrates that the core will remain sufficiently borated to preclude an inadvertent return to criticality. The licensee's calculation is performed in accordance with WCAP-8339, "Westinghouse Emergency Core Cooling System Evaluation Model – Summary" (Reference 57), and containment sump boron concentrations were used to develop a core reactivity limit that was confirmed as part of the Westinghouse Reload Safety Evaluation Methodology (Reference 34).

The licensee's subcriticality calculations employed assumptions that minimized available boron concentrations and maximized available boron dilution sources. The licensee also assumed uniform boron mixing in the sump, and the sump boron concentration was calculated as a function of pre-trip RCS conditions. The licensee calculated a post-LOCA subcriticality boron limit curve for SPU plant conditions, and stated that cycle-specific reload SEs will ensure that the core will remain subcritical following a LOCA. The staff finds that the licensee adequately accounts for post-LOCA subcriticality following a LOCA, because the licensee has calculated a conservative post-LOCA sump boron concentration and uses NRC-approved reload methods to confirm that this concentration of boron will keep the core subcritical.

The licensee's post-LOCA long-term cooling analysis was provided in a supplemental letter (Reference 58) to the licensee's methods application (Reference 53). The NRC approved the post-LOCA long-term cooling analysis in Amendment 144 to the CPSES, Units 1 and 2 Facility Operating Licenses (Reference 27).

Reference 27 presents the NRC staff's evaluation of post-LOCA long-term cooling for CPSES, Units 1 and 2 at uprated conditions. The NRC staff concluded that the post-LOCA long-term

cooling analysis was adequate, based on appropriate assumptions employed by the licensee, and on the operator actions credited in the licensee's analysis. The NRC staff also performed audit calculations of the licensee's analysis, which are discussed in Reference 27. The NRC staff found that the licensee's post-LOCA long-term cooling analysis provided reasonable assurance that the analyses, operator actions, and EOP changes to facilitate the successful control of boric acid following all LOCAs would satisfy the long-term cooling requirements of 10 CFR 50.46(b)(5) .

2.8.5.6.3.3 Conclusion

The NRC staff has reviewed the licensee's analyses of the LOCA events and the ECCS. The NRC 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 NRC staff further concludes that the licensee has demonstrated that the RPS and the ECCS will continue to ensure that the PCT, 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 NRC staff concludes that the plant will continue to meet the requirements of GDC-4, GDC-27, and GDC-35, and 10 CFR 50.46 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the LOCA.

2.8.5.7 Anticipated Transients Without Scram

2.8.5.7.1 Regulatory Evaluation

Anticipated transients without scram (ATWS) is defined as an AOO followed by the failure of the reactor portion of the protection system specified in GDC-20. For Westinghouse plants, the regulation at 10 CFR 50.62 requires that each PWR must have equipment that is diverse from the RTS 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 RTS.

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 uprated conditions.

In addition, for Westinghouse plants (e.g., CPSES), the NRC 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 MTC and the primary system relief capacity.

The NRC 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 NRC staff reviewed the licensee's justification of the applicability of generic vendor analyses to its plant and the operating conditions for the proposed SPU. Review guidance is provided in Matrix 8 of RS-001 (Reference 1).

2.8.5.7.2 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 (Reference 41), and must not exceed the ASME Service Level C limit of 3200 psig.

The limiting ATWS events, with respect to RCS pressurization, are the LOL and loss of LONF events. These events were re-analyzed in the manner of the analyses reported in NS-TMA-2182 (Reference 59). The results indicated that CPSES, Unit 1, with the Δ76 SGs, produced the higher peak RCS pressures. Therefore, CPSES, Unit 1 was used as the basis for subsequent calculations, to show compliance with the analytical basis of the ATWS Rule.

The analyses of NS-TMA-2182 represent LOL and LONF ATWS events that are conservative for 95 percent of core life. This leaves an unfavorable exposure time (UET) of 5 percent of an operating cycle. UET is the portion of core life during which the core reactivity feedback would not be capable of reducing core power to levels that would result in ATWS-generated peak RCS pressures of less than the Service Level C pressure limit of 3200 psig. The licensee demonstrates that the analytical basis for the final ATWS rule continues to be met by showing that the ATWS pressure limit of 3200 psig is met for at least 95 percent of the cycle, for each cycle. This is the approach that was used for the Byron and Braidwood units, in 1995 (Reference 60), and it has been accepted by the NRC staff.

Basically, UET is calculated by comparing the reactivity conditions of the core and plant conditions that lead to a peak RCS pressure of 3200 psig, calculated via a code like RETRAN or LOFTRAN to correspondent reactivity conditions, at various burnup levels, calculated by more detailed physics models, like ANCO. If the reactivity feedback from ANCO matches or exceeds the feedback used in the RETRAN or LOFTRAN model, then there is adequate feedback, at that burnup or stage in the cycle, to limit the RCS peak pressure to 3200 psig or less. These comparisons, repeated for the range of burnup levels, determine the UET for the cycle. The licensee asserts that this process will used for each core cycle design.

The staff agrees that this is an acceptable means to show compliance with the analytical basis of the ATWS Rule.

The staff applied a simple calculation, based upon the results of NS-TMA-2182 (Reference 59), to check the CPSES plants' response to ATWS. The LOL ATWS yielded a peak RCS pressure of 2780 psia (Reference 41) for a four-loop plant, equipped with Model D SGs. This peak RCS pressure is less than the peak RCS pressure calculated for a four-loop plant equipped with the feedring-type Model 51 SGs. The comparison is consistent with the licensee's finding, i.e., the CPSES, Unit 1 LOL ATWS analysis, based on the feedring-type Δ76 SGs, produced a higher RCS peak pressure than did the LOL ATWS of CPSES, Unit 2, with its Model D-5 SGs. Hence, the CPSES design features are covered by the Westinghouse generic analyses. The NS-TMA-2182 analysis was based upon a nominal core power level of 3427 MWt, and there was a sensitivity of +22 psi in peak pressure per additional MWt. Therefore, the NS-TMA-2182 prediction for CPSES, Unit 2 would be 2884 psig, well below the 3200 psig limit.

The staff concludes that the licensee has demonstrated that the analytical basis for the final ATWS rule continues to be met for operation of CPSES, Unit 1, equipped with Model Δ76 SGs, and of CPSES, Unit 2, equipped with Model D-5 SGs, under SPU conditions.

2.8.5.7.3 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 SPU on ATWS. The NRC 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 SPU. 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 NRC staff finds the proposed SPU acceptable with respect to ATWS.

2.8.6 Fuel Storage

2.8.6.1 New Fuel Storage

2.8.6.1.1 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.

2.8.6.1.2 Technical Evaluation

Regarding new fuel storage, the licensee concluded: (1) there are no pertinent fuel design changes implemented in support of the SPU; (2) there is no increase in the Technical Specification maximum allowed fuel enrichment of 5.0 weight percent U-235 for the SPU; and (3) there are no modifications to the new fuel storage vault for the SPU. The licensee

concluded, and the NRC staff agrees based on the above, that further analysis was not required. Therefore, the NRC staff concludes that the proposed uprate is acceptable with respect to new fuel storage.

2.8.6.1.3 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 SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the new fuel storage.

2.8.7 Additional Review Areas

2.8.7.1 Auxiliary Systems Pumps, Heat Exchanges, Valves, and Tanks

The licensee conducted a review of tanks, pumps, valves, and heat exchangers from reactor auxiliary cooling water systems that are required for safe shutdown of the plant during all conditions and for accident prevention and or mitigation. The review included evaluation of structural and flow capacity of the component pressure boundaries, and focused on the effects of the proposed SPU on the various systems' components continued functionality, including the continued capability to provide heat sink capacity and withstand any adverse dynamic loads.

The licensee listed the components in SPULR Tables 2.8.7.1-1 through 2.8.7.1-5. The staff reviewed the tables, compared them to piping and instrumentation diagrams contained in the licensee's FSAR, and found no omissions. The staff did not review the adequacy of the licensee's evaluations and makes no determination regarding said adequacy. Such review is outside the scope of RS-001, as it pertains to the NRC staff review.

2.8.7.2 Natural Circulation Cooldown

NRC Review Standard RS-001 does not explicitly provide guidance for post-uprate licensing basis reviews for natural circulation. As a part of the original CPSES licensing bases, however, the licensee provided the NRC with information documenting compliance with NRC BTP RSB 5-1, "Design Requirements of the Residual Heat Removal System." The BTP required that test programs for PWRs include tests with supporting analyses to (1) confirm that adequate mixing of borated water added prior to or during cooldown can be achieved under natural circulation conditions and permit estimation of the times required to achieve such mixing, and (2) confirm that the cooldown under natural circulation conditions can be achieved with the limits specified in the EOPs. In addition, the plant is to be designed so that the reactor can be taken from normal operating conditions to cold shutdown using only safety-grade systems.

The NRC staff found that a comparison of performance to that of previously tested plants of similar design may be substituted for these tests. The licensee provided such comparisons to the NRC relating a boron mixing and cooldown test that was performed at Diablo Canyon Unit 1 (DCPS1), which the NRC staff found acceptable by letter dated October 18, 1988.

The licensee noted the following in comparison to reactor system design between CPSES and DCPS1:

(1) The general configuration of piping and components in each RCL is the same,

(2) DCPS1 has a longer SG tube bundle than CPSES, Unit 2, resulting in a 4-9 percent higher driving head than at CPSES, Unit 2. The CPSES, Unit 1 SGs have a slightly higher driving head than the DCPS1 SGs,

(3) The CPSES, Unit 2 SG incorporates a preheater, whereas the CPSES, Unit 1 and DCPS1 SGs incorporate feedwater rings. The licensee stated that the preheater unit has negligible effects on flow conditions because the AFW does not pass through the preheater,

The licensee concluded that, based on comparison of hydraulic loss coefficients, the CPSES units would have a natural circulation flow rate 2 to 7 percent higher than DCPS1. In consideration of differences in driving heads and RCP loss coefficients, the natural circulation flow at CPSES would be approximately 7 percent lower than that observed at DCPS1. The staff reviewed the licensee's evaluation and finds that the configuration of CPSES, Units 1 and 2 remains largely the same as previously evaluated, and agrees with the licensee's conclusion that the 1987 comparison between CPSES and DCPS1 remains applicable.

Boron mixing evaluations were performed in support of the CPSES uprate. The licensee stated that two safety-grade boric acid tanks could provide adequate supply of borated water to change boron concentration by 300 ppm in approximately 1 hour without letdown. This calculation assumed a total boration rate of 75 gpm. The licensee identified alternative methods of boron and depressurization, such that boration may continue in the event that letdown is necessary, or if instrument air is lost.

The licensee stated that CPSES, Units 1 and 2 are T_{cold} plants, and as such, sufficient bypass flow exists to make the temperature of the upper head fluid essentially equal to the cold leg temperature. This condition precludes void formation in the upper head region, which was a concern at the DCPS1 test, because DCPS1 is a T_{hot} plant. Due to design differences between CPSES and DCPS1, which include a much larger vessel head at CPSES, the licensee stated that the DCPS1 test demonstrates that CPSES can sustain natural circulation cooldown acceptably, because its upper head would cool at a rate comparable to or faster than DCPS1.

The licensee stated that pressure control and depressurization capability are similar to DCPS1 due to similarities in the design of the RCS and CVCS. Ambient heat losses will gradually reduce RCS pressure, and pressurizer PORVs and auxiliary spray are effective in depressurizing the RCS when needed to permit RHR system initiation.

The licensee also provided an evaluation of natural circulation, boron mixing, and cooldown. The evaluation considered operator actions consistent with the Westinghouse Owners Group Emergency Response Guidelines, and demonstrated adequate boron mixing and natural circulation cooldown capabilities. On the basis of the evaluation, and acceptable comparison to the DCPS1 test, the staff finds the Natural Circulation Cooldown evaluation acceptable for the proposed SPU.

2.8.7.3 Mid-Loop Operation

The licensee reviewed the current licensing basis at CPSES, Units 1 and 2 to determine whether identified actions taken to preclude loss of decay heat removal during non-power operation in response to GL 88-17, “Loss of Decay Heat Removal,” were affected by the proposed SPU (Reference 61). The licensee concluded that the adequacy of the CPSES, Units 1 and 2 design as it pertains to GL 88-17 is addressed as a part of the outage risk management.

As a part of outage planning, the licensee performs an evaluation that includes a “time to boil” calculation to address the concerns identified in GL 88-17. The proposed SPU will increase the decay heat load at CPSES, which will affect this calculation. The outage management evaluations will incorporate the uprated design of CPSES, and be incorporated into the licensee’s overall outage risk management assessment. Finally, plant modifications, training, and procedure changes have been implemented at CPSES, Units 1 and 2, and ongoing changes will be continuously implemented for the SPU.

The NRC staff reviewed the licensee’s evaluation of mid-loop operation. The licensee adequately accounted for changes resulting from the SPU that could affect outage risk management, and on this basis, the staff concludes that the licensee’s approach to GL 88-17 remains acceptable in light of the proposed SPU.

2.9 Source Terms and Radiological Consequences Analyses

This SE input addresses the impact of the proposed changes on previously analyzed DBA radiological consequences, and the acceptability of the revised analysis results. The regulatory requirements on which the NRC staff based its acceptance are the accident dose guidelines of 10 CFR, Part 100, Section 100.11, “Determination of exclusion area, low-population zone, and population center distance,” and 10 CFR Part 50 Appendix A, GDC-19, “Control room.” The NRC staff’s evaluation is also based upon relevant information in RGs and standards, the CPSES FSAR, TS, and applicable previous licensing actions for CPSES. The remainder of this SE is placed in the RS-001, “Review Standard for Extended Power Uprates,” SE format as applicable to the CPSES SPU submittal.

2.9.1 Source Terms for Radwaste Systems Analyses

2.9.1.1 Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with the proposed SPU 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 NRC 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) the concentrations of all radionuclides other than fission products in the reactor coolant, (4) the leakage rates and associated fluid activity of all potentially radioactive water and steam systems, and (5) the potential sources of radioactive materials in effluents that are not considered in the CPSES

FSAR related to LWMS and GWMS. The NRC's acceptance criteria for source terms are based on (1) 10 CFR Part 20, in so far 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 ALARA criterion; and (3) GDC-60, in so far 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.

2.9.1.2 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 updated the calculation of radiological sources to account for the projected increase in core power level and also to account for the longer fuel cycles and higher fuel enrichments and burnup that are characteristic of more recent fuel cycle designs. The licensee recalculated the maximum reactor coolant fission product activity concentration assuming 1 percent failed fuel, and the expected reactor coolant concentration 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.

In the CPSES analysis for the SPU, the licensee calculated the total core isotopic inventory of noble gas and iodine isotopes at the end of an equilibrium fuel cycle consisting of a three region core with the regions operating for 495, 990, and 1485 effective full-power days (EFPDs). The licensee recalculated core inventory using a core power level of 3684 MWt with additional margins added to account for core power uncertainty and potential future fuel cycle design differences. The core operating scenario consisted of irradiation times of 495, 990, and 1485 EFPDs resulting in a final discharge region burnup of 66,000 megawatt days per metric ton uranium (MWD/MTU). The licensee used the isotope generation and depletion code, ORIGEN-S, which is an appropriate code according to RG 1.195. The licensee used the same methodology that was used in the CPSES FSAR and used inputs and assumptions in the calculation to reflect the uprated power, and appropriate fuel enrichment and burnup per the SPU submittal. Therefore, the NRC staff finds this change acceptable.

The licensee calculated the maximum reactor coolant fission product activity concentration assuming 1 percent failed fuel using the methods and models outlined in Section 11.1 of the CPSES FSAR. The calculations assumed operation at a core power of 3684 MWt with irradiation times of 495, 990, and 1485 EFPDs, resulting in a final discharge region burnup of 66,000 MWD/MTU. The assumed core power of 3684 MWt includes a power measurement uncertainty of 2 percent. Other inputs and assumptions, as well as the methods and models, were unchanged from the original CPSES design basis as specified in FSAR Section 11.1. The NRC staff finds that the licensee has used the appropriate core power assumptions for the SPU calculation of the average reactor coolant fission product activity concentration. The NRC staff also finds that the SPU would not impact any of the other inputs and assumptions to the maximum coolant fission product concentration calculations, so continued use of the current FSAR values is acceptable. The staff finds that the licensee has appropriately calculated the maximum reactor coolant fission product activity concentration for the SPU.

The licensee calculated the average reactor coolant fission product activity concentration using the ANSI/ANS-18.1-1984 methodology. ANSI/ANS-18.1-1984 is an acceptable methodology to the NRC staff. Application of this standard is consistent with guidance in SRP 11.1. Normal sources for CPSES are established by appropriate scaling by thermal power and other pertinent SPU parameters as outlined in the standard.

2.9.1.3 Conclusion

The NRC staff has reviewed the radioactive source term associated with the proposed SPU and concludes that the proposed parameters and resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. The NRC 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 NRC staff finds the proposed SPU acceptable with respect to source terms.

2.9.2 Radiological Consequences of Main Steamline Failures Outside Containment

2.9.2.1 Regulatory Evaluation

The NRC staff reviewed the analyses of the radiological consequences of an MSLB outside the containment. The NRC staff's review included (1) the sequence of events, models and assumptions used by the licensee for the calculation of the radiological doses; (2) the evaluation of the TSs on the primary and secondary coolant iodine activities; and (3) the determination of reactor coolant iodine concentration corresponding to a pre-accident 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 CR under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident, and (2) 10 CFR Part 100, insofar as it establishes requirements for assuring that radiological doses from postulated accidents will be acceptably low. Specific review criteria are contained in SRP Sections 6.4 and 15.1.5.A

2.9.2.2 Technical Evaluation

In its August 28, 2007, submittal, the licensee stated that the MSLB analysis was performed using the analytical methods and assumptions presented in the current licensing basis analysis with appropriate changes to reflect the SPU conditions. The specific changes include:
(1) revised source terms were used that reflected the core power uprate to 3612 MWt; (2) the SG and RCS masses have been updated; (3) steam releases are recalculated as described in the SPULR, Section 2.9.10; and (4) the time required to cool the RCS below 212 °F, terminating releases from the faulted SG has been increased to 25.75 hours. Any other MSLB dose analysis assumptions are the same as in the current licensing basis calculation, which was previously reviewed and approved in Amendment No. 130 issued by letter dated February 20, 2007.

The postulated MSLB accident considered is the complete severance of the largest MS line outside the primary containment. The radiological consequences of an MSLB break outside containment will bound the radiological consequences of a break inside containment. Therefore, only the MSLB outside of containment is considered with regard to the radiological consequences. The affected SG, hereafter referred to as the faulted SG, rapidly depressurizes and releases the initial contents of the SG to the environment. The MSLB accident is described in Section 15.1.5 of the CPSES FSAR. RG 1.195, "Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light-Water Nuclear Power Reactors" Appendix F identifies acceptable radiological analysis assumptions for a PWR MSLB.

The steam release from a rupture of a MS line would result in an initial increase in steam flow, which decreases during the accident as the steam pressure decreases. The licensee's evaluation indicates that no fuel damage is predicted as a result of an MSLB accident. Therefore, consistent with the current licensing analysis basis and RG 1.195, the licensee performed the MSLB accident analyses assuming that the accident occurs at the uprated full power. The licensee considered two radioiodine spiking cases consistent with the guidance in RG 1.195.

The first case is referred to as pre-accident iodine spike and assumes that a reactor transient has occurred prior to the postulated MSLB that has raised the primary coolant iodine concentration to the maximum value permitted by the TS for spiking conditions. For CPSES, the maximum iodine concentration allowed by the TS as a result of an iodine spike is 60 microcuries per gram (µCi/gm) dose equivalent (DE) I-131.

The second case assures that the primary system transient associated with the MSLB causes an iodine spike in the primary systems. This case is referred to as a concurrent iodine spike. The increase in primary coolant iodine concentration is estimated using a spiking model that assumes that the iodine release rate from fuel rods to the primary coolant increases to a value 500 times greater than the release rate corresponding to the iodine concentration at the equilibrium value specified in TSs for normal operation. For CPSES, the RCS TS limit for normal operation is 0.45 µCi/gm DE I-131. The licensee used a value of 1.0 µCi/gm DE I-131 in its calculations to determine the boundary doses.

For the MSLB accident, the licensee evaluated the radiological dose contribution from the release of secondary side activity using the equilibrium secondary side-specific activity TS limiting condition for operation (LCO) of 0.1 µCi/gm dose equivalent iodine (DEI).

The licensee used a higher core-rated power for its radiological consequence analyses. When the core-rated power rises, the RCS pressure also rises. The RCS has a higher fluid density at the higher pressure (assuming a constant temperature), and subsequently has a higher RCS mass available for release. A maximum initial SG mass in the faulted-loop SG has been used in all of the analyzed cases. The rapid depressurization that occurs following a steam line rupture typically results in large amounts of water being added to the SGs through the main FW system. Therefore, the SG liquid mass increases. The licensee recalculated the initial RCS fluid mass and SG fluid mass based on the calculated system response, temperatures and pressures for the uprated thermal power. These recalculated values were used as input to the DBA dose analyses to reflect the uprate conditions. Based on the discussion above, the NRC staff finds the changes made to the initial RCS and SG masses acceptable.

In order to maximize the CR dose, the licensee assumed that the steam line break occurs in the turbine building. The affected SG is assumed to release steam for 25.75 hours, which is the time required for the RCS to be cooled down to 212 °F, crediting safety-grade equipment only. The 25.75-hour time period has increased from the current licensing basis time of 20 hours because the proposed increase in thermal power will produce more heat and therefore takes a longer time period for the RCS to be cooled. This was confirmed by the licensee to be a bounding assumption for the SPU.

The amount of steam released to the atmosphere depends on the sensible heat and decay heat generated, while reducing the RCS temperature from the full-power values to the shutdown conditions. The calculation is an energy balance that determines the amount of heat that would be dissipated via steam release through the SG safety valves or ARVs. The energy balance considers the heat generated in the core, heat released or absorbed by thick metal in the RCS and the intact SGs, and heat released or absorbed within the fluids in the RCS and the intact SG. The energy that cannot be stored within the defined boundary of the RCS and intact SGs is removed via steaming and the purpose of the calculation is to determine the steam mass released. The decay heat model predates the ANS standard. It includes decay heat and residual fissions based on 1 percent SDM. The decay heat values used in this calculation are more conservative than the 1979 ANS + 2σ model. For the steam line break event, only three SGs are considered to be intact. The NRC staff reviewed these calculations and determines that the results are consistent with and continues to comply with the current licensing basis and acceptance requirements associated with the radiological analysis.

The licensee evaluated the accident assuming a concurrent LOOP. Due to the assumption of a LOOP, the condenser is unavailable and cooldown of the primary system is accomplished through the release of steam from the intact SG ARVs.

For the affected SG, the licensee assumed the release passes directly into the turbine building with no credit taken for holdup, partitioning, or scrubbing by the SG liquid. The licensee did not take credit for any holdup or dilution in the turbine building. The licensee's analysis assumes the release into the turbine building is exhausted to the environment and subsequently transported from the environment into the CR assuming conservative atmospheric dispersion factors.

In its August 28, 2007, letter, the licensee stated that the radioactive steam releases to the environment were recalculated to reflect the SPU conditions. This recalculation is described in CPSES SPULR Section 2.9.10. Steam releases from the unaffected/intact SGs are determined for the intervals 0-to-2 hours and 2-to-11 hours. By the end of the 2-hour time frame, the RCS and intact SGs are assumed to be in a steady-state condition. Steam release will be required until the RHR system is placed in-service and removing all decay and sensible heat. It has been conservatively assumed and 11 hours of steam release could occur prior to placing the plant in the RHR mode of operation. After the first 2 hours, it is assumed the plant will have cooled down and stabilized at no-load conditions. The additional 9 hours are conservatively longer than the actual time required to cool down and depressurized the plant from no-load conditions to the RHR operating conditions. The NRC staff reviewed these calculations and determines that the results are consistent with and continues to comply with the current licensing basis and acceptance requirements associated with the radiological analysis.

The near instantaneous release of the secondary coolant from the affected SG represents a significant contribution to the total dose from an MSLB, since the secondary coolant inventory is evaluated at 0.1 µCi/gm DEI-131. The licensee conservatively assumed that during the first 25.75 hours, primary coolant leaks into the affected SG at the rate of 500 gallons per day (gpd) (0.35 gpm) directly releasing all of the coolant activity to the environment. This release is assumed to continue for 25.75 hours, until the RCS has cooled to below 212 °F, at which time the release from this pathway terminates. The licensee assigned 0.65 gpm primary-to-secondary side leakage to the three intact SGs. The licensee assumed that this leakage continues for 8 hours.

An assumed iodine partition factor in the unaffected SGs results in 1 percent of the iodine in the SG bulk liquid being released to the environment at the steaming rate. Radionuclides initially in the steam space do not provide any significant dose contribution. The transport to the environment of noble gases from the primary coolant is assumed to occur without any mitigation or holdup.

2.9.2.3 Conclusion

The NRC staff has evaluated the licensee's revised 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 SPU on these analyses. The NRC 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 whole-body and thyroid doses at the exclusion area boundary (EAB) and the low-population zone (LPZ) outer boundary meet the exposure guideline values specified in 10 CFR 100.11 (assuming a pre-accident iodine spike) and are a small fraction of the 10 CFR Part 100 values for the concurrent iodine spike. The NRC staff also concludes that the CR meets the dose requirements of GDC-19 for DBAs. The NRC staff's review has found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance in RG 1.195. The assumptions found acceptable to the NRC staff are presented in Tables 2.9-1 and 2.9-4. Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to the radiological consequences of MSLB accidents outside the containment.

2.9.3 Radiological Consequences of a Reactor Coolant Pump Locked-Rotor Accident

2.9.3.1 Regulatory Evaluation

The NRC staff reviewed the analyses of the radiological consequences of an RCP locked-rotor accident (LRA). The review included (1) determination of a need for a radiological consequences analysis; and (2) 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 an RCP LRA 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 whole body, or its equivalent to any part of the body, for the duration of the accident, and (2) 10 CFR Part 100, insofar as it establishes requirements for assuring that radiological doses from

postulated accidents will be acceptably low. Specific review criteria are contained in SRP Sections 6.4 and 15.3.3-15.3.4.

2.9.3.2 Technical Evaluation

In its August 28, 2007, submittal, the licensee stated that the LRA analysis was performed using the analytical methods and assumptions presented in the current licensing basis analysis with appropriate changes to reflect SPU conditions. The specific changes include: (1) revised source terms were used that reflected the core power uprate to 3612 MWt; (2) the SG and RCS masses have been updated (as discussed in Section 2.9.2 of this SE); (3) 15 percent of fuel rods are assumed to violate the departure from DNB limit; and (4) steam releases are recalculated as described in CPSES SPULR 2.9.10. All other LRA dose analysis assumptions are the same as in the current licensing basis calculation, which was previously reviewed and approved in Amendment No. 130 dated February 20, 2007.

The accident considered begins with the instantaneous seizure of an RCP rotor, which causes a rapid reduction in the flow through the affected RCS loop. The sudden decrease in core coolant flow while the reactor is at-power causes a degradation of core heat transfer, resulting in localized temperature and pressure changes in the core. The low-coolant flow causes a degradation of core heat transfer resulting in localized temperature and pressure changes in the core. As a result, the licensee assumes that fuel cladding damage occurs due to a DNB. Activity from the fuel damage is transported to the secondary side due to primary-to-secondary side leakage evaluated at the TS limit. It is assumed that the LRA does not cause an increase in the magnitude of the pre-existing primary-to-secondary leakage.

In CPSES SPULR, Section 2.8.3.2, the licensee describes its DNB calculation for SPU conditions. To estimate the radiation release possible as a consequence of the accident, DNB calculations were performed to quantify the inventory of rods that would experience DNB and be conservatively presumed to fail. As a result, the licensee has determined that 15 percent of the core fuel gap activity would be released to the RCS. The LRA dose analysis assuming 15 percent failed fuel rods bounds the results of DNB analysis under SPU conditions. The fuel rod gap fission product inventory was calculated based on the core inventory at the uprated power with a 2 percent measurement uncertainty.

The radioactivity in the RCS is assumed to be transported to the secondary side with primary-to-secondary leakage of 1 gpm total. The licensee assumed that the release continues for 8 hours after which RHR is placed in service. The radioactive steam releases to the environment were recalculated for SPU conditions and are described in CPSES SPULR Section 2.9.10. The calculation for steam releases from intact SGs for LRA is the same as described for MSLB (section 2.9.2 of this SE) except that for the LRA all SGs are considered to be intact. The SG and RCS liquid masses have been updated to account for the uprate thermal power.

The licensee used the RADTRAD 3.03 computer code to model the time dependent transport of radionuclides, from the primary-to-secondary side and consequently to the environment via the ARVs. The licensee's analysis conforms to Appendix G of RG 1.195, which identifies acceptable radiological analysis assumptions for an LRA.

2.9.3.3 Conclusion

The NRC staff has evaluated the licensee's revised analyses for the radiological consequences of an RCP locked rotor and concludes that the licensee has adequately accounted for the effects of the proposed SPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated LRA since the calculated whole-body and thyroid doses at the EAB and the LPZ outer boundary are a small fraction of exposure guideline values specified in 10 CFR 100.11. The NRC staff also concludes that the CR meets the dose requirements of GDC-19 for DBAs. The NRC staff's review has found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance in RG 1.195. The assumptions found acceptable to the NRC staff are presented in Tables 2.9-1 and 2.9-5. Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to the radiological consequences of a LRA.

2.9.4 Radiological Consequences of a Control Rod Ejection Accident

2.9.4.1 Regulatory Evaluation

The NRC staff reviewed the analyses of the radiological consequences of a CREA. The NRC staff's review included the plant response to a CREA and the calculation of radiological doses at the EAB and LPZ outer boundary and in the CR due to the releases resulting from an REA. The purpose of the NRC staff's review was to (1) ensure that plant's procedures for recovery from an REA and the plant's TSs are properly taken into account in computing the doses and (2) compare the calculated doses against the appropriate guidelines. The NRC's acceptance criteria for the radiological consequences of a CREA 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 whole body, or its equivalent to any part of the body, for the duration of the accident, and (2) 10 CFR Part 100, insofar as it establishes requirements for assuring that radiological doses from postulated accidents will be acceptably low. Specific review criteria are contained in SRP Sections 6.4 and 15.4.8.A.

2.9.4.2 Technical Evaluation

In its August 28, 2007, submittal, the licensee stated that the CREA analysis was performed using the analytical methods and assumptions presented in the current licensing basis analysis with appropriate changes to reflect SPU conditions. The specific changes include: (1) revised source terms were used that reflected the core power uprate to 3612 MWt; (2) the SG and RCS masses have been updated (as discussed in Section 2.9.2 of this SE); (3) 15 percent of fuel rods are assumed to violate the DNB limit; (4) steam releases are recalculated as described in CPSES SPULR 2.9.10; and (5) consistent with the rods-in-DNB assumption, 0.375 percent of the fuel in the core is assumed to melt. All other CREA dose analysis assumptions are the same as in the current licensing basis calculation, which was previously reviewed and approved in Amendment No. 130 dated February 20, 2007.

This accident is defined as the mechanical failure of a control rod mechanism pressure housing, resulting in the ejection of a RCCA and drive shaft. The consequence of this mechanical failure

is a rapid positive reactivity insertion, together with an adverse core power distribution. For this accident, localized damage to fuel cladding and a limited amount of fuel melt are projected. In CPSES SPULR, Section 2.8.5.4.6.2, the licensee describes its DNB analysis for gap activity and fuel inventory melting for CREA at SPU conditions. The licensee assumed that as a result of localized fuel cladding damage, 15 percent of the gap activity is released to the primary coolant. In addition, the licensee assumes that 0.375 percent of the fuel inventory is also released to the primary coolant as a result of limited fuel melting. The CREA dose analysis assuming 15 percent failed fuel rods and 0.375 percent fuel melting bound the calculated results of DNB analysis under SPU conditions. The mechanical failure breaches the RPV head resulting in a release of primary coolant to the containment atmosphere. Releases to the environment are assumed to occur through two separate pathways:

- Release of containment atmosphere (using design leakage assumptions), and
- Release of RCS inventory via primary-to-secondary leakage through SGs.

To evaluate the release to containment atmosphere, the licensee used the guidance from Appendix H of RG 1.195. The licensee assumed that 15 percent of the fuel rods in the core fail cladding, releasing the fission product inventory in the fuel rod gap. The licensee assumed that 10 percent of the core inventory of iodines and noble gases is in the fuel rod gap. Therefore, for the fuel clad failure, the fraction of core activity released is 0.015 for both iodines and noble gases. In addition, the licensee assumed that localized heating causes 0.375 percent of the fuel to melt, releasing 25 percent of the iodines and 100 percent of the noble gases contained in the melted fuel. As a result of the fuel melt portion of the fuel damage, the fraction of the core halogen activity released is 0.000938 (0.00375 x 0.25) and the fraction of noble gas activity released is 0.00375. The total activity released as a result of the fuel damage from the CREA is the sum of the clad failure fraction and the fuel melt fraction.

For the first release case through containment leakage, the radioactivity release from the fuel as described above was assumed to be released instantaneously into the containment. The licensee has determined that containment sprays will not initiate due to a CREA and, as a result, the licensee did not evaluate dose contributions from ECCS leakage and RWST back leakage as in the LOCA analysis. The containment is assumed to leak at the TS leak rate, L_a. The licensee assumed that the containment leak rate is reduced by 50 percent at 24 hours for both the offsite and the CR analyses.

The second release path evaluated by the licensee is via the secondary system. The licensee based the evaluation of the activity in the secondary system release on the guidance in Appendix H of RG 1.195. The core release fractions for iodines and noble gases are based on the assumed consequences of 15 percent failed fuel and 0.375 percent melted fuel, as in the containment release case. To evaluate the fuel clad failure portion of the fuel damage, the fraction of core activity released is 0.015 for both iodines and noble gases as in the containment release case. For the secondary release pathway, the licensee assumed that 50 percent of the iodines and 100 percent of the noble gases contained in the melted fuel are released to the RCS. Therefore, as a result of the fuel melt portion of the fuel damage the fraction of the core halogen activity released to the RCS is 0.00188 (0.0037 x 0.5) and the fraction of noble gas activity released is 0.00375.

For the secondary system release case, the licensee assumed that fission products released from the fuel are instantaneously and homogeneously mixed in the RCS and transported to the secondary side of the SGs via primary-to-secondary leakage at the TS value of 1 gpm for 8 hours. The licensee has determined that, for this event, an 8-hour time period is required to cut in the RHR for decay heat removal. This results in termination of steaming from the SG, which terminates the releases. A LOOP is conservatively assumed to occur at T = 0, rendering the main condenser unavailable. With the main condenser unavailable, the plant is cooled down by releases of steam to the environment via the relief valves. During the first 8 hours of the accident the only steam release is assumed to be via the secondary safety valve. When the primary system pressure drops below the secondary side pressure, the relief valve closes. The licensee assumed the chemical form of the iodines released from the SGs to be 97 percent elemental and 3 percent organic as is consistent with the RG 1.195. As in the evaluation of the MSLB accident, the licensee assumed an iodine partition factor of 100 in the SGs and assumed that the noble gas activity released to the secondary system is released to the environment without reduction or mitigation.

In the response to the NRC staff's RAI, in a letter dated January 31, 2008, the licensee stated that the steam releases calculated in CPSES SPULR Section 2.9.10 for the LRA were used in the CREA analysis. The reason being that the cooldown for each analysis is the same in that the RCS is intact and all of the SGs are available for plant cooldown. The NRC staff has reviewed this information and determined that the results are consistent with and continues to comply with the current licensing basis.

2.9.4.3 Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of an REA and concludes that the licensee has adequately accounted for the effects of the proposed SPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated CREA since the calculated whole-body and thyroid doses at the EAB and the LPZ outer boundary are well within the exposure guideline values specified in 10 CFR 100.11. The NRC staff also concludes that the CR meets the dose requirements of GDC-19 for DBAs. The NRC staff's review has found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance in RG 1.195. The assumptions found acceptable to the NRC staff are presented in Tables 2.9-1 and 2.9-6. Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to the radiological consequences of a CREA.

2.9.5 Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment

2.9.5.1 Regulatory Evaluation

The NRC staff reviewed the analyses of the radiological consequences of failures outside the containment of small lines connected to the primary coolant pressure boundary (e.g., instrument lines and sample lines). The NRC staff's review included (1) the identification of small lines postulated to fail and the isolation provisions for these lines; (2) the failure scenario; (3) the models and assumptions for the calculation of the radiological doses for the postulated failure;

and (4) an evaluation of the primary coolant iodine activity, including the effects of a concurrent iodine spike, and the TSs for the reactor coolant iodine activity. The NRC's acceptance criteria for the radiological consequences of the failure of small lines carrying primary coolant 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 CR under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident, and (2) GDC-55, insofar as it establishes isolation requirements for small-diameter lines connected to the primary system that form the basis of meeting 10 CFR 100.11. Specific review criteria are contained in SRP Sections 6.4 and 15.6.2.

2.9.5.2 Technical Evaluation

In its August 28, 2007, submittal, the licensee stated that the failures of small lines carrying primary coolant outside containment analysis was performed using the analytical methods and assumptions presented in the current licensing basis analysis with appropriate changes to reflect SPU conditions. The specific changes include: (1) revised source terms were used that reflected the core power uprate to 3612 MWt and (2) the RCS mass has been updated (as discussed in Section 2.9.2 in this SE). All other small line failures dose analysis assumptions are the same as in the current licensing basis calculation, which was previously reviewed and approved in Amendment No. 130 dated February 20, 2007.

This event assumes a complete severance of the 3-inch CVCS letdown line just outside containment, between the outboard letdown isolation valve and letdown heat exchanger, at full-rated power condition. The severance of the letdown line results in a loss of reactor coolant at the rate of 190 gpm, which is in the makeup capacity of any two of the three charging pumps, as found acceptable in the CPSES current licensing basis. The licensee assumes that 20.1 percent of the leaking coolant flashes to steam and that all of the iodine in this steam is assumed to become airborne and is available for release to the atmosphere. Also, all noble gases contained in the leaking primary coolant are available for release to the atmosphere. The time required for the operator to identify the accident and initiate the closure of the letdown isolation valve is expected to be within 30 minutes after accident initiation including 10 seconds for the letdown isolation valve closure time.

This event is not listed as an accident in RG 1.195, but is discussed in SRP 15.6.2 "Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment," where the appropriate accident-specific dose acceptance criteria are given. These offsite dose criteria are a small fraction (i.e. 10 percent) of the 10 CFR 100.11 limits. In its reanalysis the licensee used the assumptions contained in the current licensing basis as discussed in CPSES FSAR.

2.9.5.3 Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of failures outside the containment of small lines connected to the primary coolant pressure boundary and concludes that the licensee has adequately accounted for the effects of the proposed SPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological

consequences of a postulated failure outside the containment of a small line carrying reactor coolant, since the calculated whole-body and thyroid doses at the EAB and the LPZ outer boundary are substantially below the exposure guideline values of 10 CFR 100.11. The NRC staff also concludes that the CR meets the dose requirements of GDC-19 for DBAs. The NRC staff's review has found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance in RG 1.195. The assumptions found acceptable to the NRC staff are presented in Table 2.9-1. Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to the radiological consequences of failures outside the containment of small lines connected to the primary coolant pressure boundary.

2.9.6 Radiological Consequences of Steam Generator Tube Rupture

2.9.6.1 Regulatory Evaluation

The NRC staff reviewed the analysis of the radiological consequences of a postulated SGTR. The NRC 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 NRC staff's review included two cases for the reactor coolant iodine concentration corresponding to a pre-accident 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 CR under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident, and (2) 10 CFR Part 100, insofar as it establishes requirements for assuring that radiological doses from postulated accidents will be acceptably low. Specific review criteria are contained in SRP Sections 6.4 and 15.6.3.

2.9.6.2 Technical Evaluation

In its August 28, 2007, submittal, the licensee stated that the SGTR analysis was performed using the analytical methods and assumptions presented in the current licensing basis analysis with appropriate changes to reflect SPU conditions. The specific changes include: (1) revised source terms were used that reflected the core power uprate to 3612 MWt; (2) the SG and RCS masses have been updated (as discussed in Section 2.9.2 of this SE); and (3) break flow and steam releases are recalculated as described in SPULR Section 2.8.5.6.2. All other SGTR dose analysis assumptions are the same as in the current licensing basis calculation, which was previously reviewed and approved in Amendment No. 130 dated February 20, 2007.

In an SGTR accident, it is assumed that there is a complete severance of a single SG tube. The accident is assumed to take place at full power with the reactor coolant fission product concentrations corresponding to continuous operation with a limited amount of fuel damage. The postulated break allows primary coolant liquid to leak to the secondary side of the affected SG with an assumed release to the environment through the SG ARVs. For this accident scenario, a LOOP is assumed to occur at reactor trip. Because the LOOP renders the main

condenser unavailable, the plant is cooled down by release of steam to the environment. In the licensee's analysis, the ARV on the affected SG is assumed to open to control SG pressure at the beginning of the event. After operator action is credited to close the affected SG ARV, the same ARV is assumed to fail fully open. The affected SG discharges steam to the environment for 30 minutes until the SG is manually isolated a second time by closure of the SG atmospheric dump block valve. Break flow into the affected SG is terminated at 5,620 seconds, at which time the RCS is at a lower pressure than the secondary system. Depressurization of the SG is necessary to allow RHR system cooling.

In SPULR Section 2.8.5.6.2, the licensee discusses its calculation of break flow and steam releases for SPU conditions. The mass-release case determines the primary-to-secondary break flows and steam releases for the SGTR radiological consequences analysis. This case is analyzed through tube rupture flow isolation and cooldown to RHR system in-service conditions to obtain the total steam releases from the intact and ruptured SGs. At this point the plant proceeds to Mode 5 (cold shutdown) conditions using the RHR system without additional steam release. The mass release analysis considered both CPSES units. The licensee determined that CPSES, Unit 1 bounds CPSES, Unit 2 for the purposes of the mass release analysis.

The NRC staff has reviewed the analysis of the SGTR accident and concludes that the analysis has adequately accounted for the plant operation at the SPU power level and was performed using acceptable analytical methods and approved computer codes. The NRC staff further concludes that the assumptions used in this analysis are conservative consistent with the guidance in RG 1.195, and that the event does not result in an overfill of the ruptured SG.

The licensee evaluated the dose consequences from discharges of steam from the three intact SGs for a period of 8 hours, until the primary system has cooled sufficiently to allow an alignment to the RHR system. At this point in the accident sequence, steaming is no longer required for cooldown and releases from the intact SGs are terminated.

Appendix E of RG 1.195 identifies acceptable radiological analysis assumptions for an SGTR accident. If a licensee demonstrates that no or minimal fuel damage is postulated for the limiting event, the activity released should be the maximum coolant activity allowed by the TS. Two radioiodine spiking cases are considered. The first case is referred to as a pre-accident iodine spike and assumes that a reactor transient has occurred prior to the postulated SGTR that has raised the primary coolant iodine concentration to the maximum value permitted by the TS for a spiking condition. For CPSES, the maximum iodine concentration allowed by the TS as a result of an iodine spike is 60 μCi/gm DE I-131.

The second case assumes that the primary system transient associated with the SGTR causes an iodine spike in the primary system. This case is referred to as a concurrent iodine spike. The increase in primary coolant iodine concentration for the concurrent iodine spike case is estimated using a spiking model that assumes that the iodine release rate from the fuel rods to the primary coolant increases to a value 335 times greater than the release rate corresponding to the iodine concentration at the TS limit for normal operation. For CPSES, the RCS TS limit for normal operation is 0.45 μCi/gm DE I-131. The licensee used a value of 1.0 μCi/gm DE I-131 in their calculations, which gives bounding doses.

The licensee's evaluation indicates that no fuel damage is predicted as a result of an SGTR accident. Therefore, consistent with the current licensing analysis basis and regulatory guidance, the licensee performed the SGTR accident analyses for the pre-accident iodine spike case and the concurrent iodine spike case.

The licensee assumed that the source term resulting from the radionuclides in the primary system coolant, including the contribution from iodine spiking, is transported to the affected SG by the break flow. In the licensee's analysis for CPSES, break flow is terminated after 30 minutes. A portion of the break flow is assumed to flash to steam because of the higher enthalpy in the RCS. The noble gas and iodine in the flashed portion of the break flow will ascend to the steam space of the affected SG and be available for release with no credit taken for scrubbing by the SG liquid. The radionuclides entering the steam space as the result of flashing pass directly to the environment through the SG ARVs. The iodine and other noble gas isotopes in the non-flashed portion of the break flow are assumed to mix uniformly with the SG liquid mass and be released to the environment in direct proportion to the steaming rate and in inverse proportion to the applicable partitioning factor. In accordance with the guidance from RG 1.195, the licensee's evaluation of the releases from the steaming of the liquid mass in the SG credits a partitioning factor of 0.01 for all noble gas isotopes. Following the applicable regulatory guidance, the licensee assumed that all noble gas radionuclides released from the primary system are released to the environment without reduction or mitigation.

The licensee assumed that the source term resulting from the radionuclides in the primary system coolant, including the contribution from iodine spiking, is transported to the intact SGs by the leak rate limiting condition for operation (1 gpm) specified in the TS. All radionuclides in the primary coolant leaking into the intact SGs are assumed to enter the SG liquid. Radionuclides initially in the SG liquid, and those entering the SG liquid from the leakage flow, are released as a result of secondary liquid boiling/steaming, with a partitioning factor of 0.01 for all non-noble gas isotopes. Therefore, one percent of the iodines are assumed to pass into the steam space and then directly to the environment. The licensee assumed that all noble gases that are released from the primary system to the intact SGs are released to the environment without reduction or mitigation. Releases were assumed to continue from the intact SGs for a period of 8 hours until the RHR system is placed in service. The 8-hour steaming period is based on the time necessary to cooldown crediting safety-grade equipment only.

2.9.6.3 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 SPU on these analyses. The NRC 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 whole-body and thyroid doses at the EAB and the LPZ outer boundary do not exceed the exposure guideline values of 10 CFR 100.11 (assuming a pre-accident iodine spike) and are a small fraction of the Part 100 values for the concurrent iodine spike. The NRC staff also concludes that the CR meets the dose requirements of GDC-19 for DBAs. The NRC staff's review has found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance in RG 1.195. The assumptions found acceptable to the NRC staff are presented in Tables 2.9-1 and 2.9-7.

Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to the radiological consequences of an SGTR.

2.9.7 Radiological Consequences of a Design-Basis Loss-of-Coolant Accident

2.9.7.1 Regulatory Evaluation

The NRC staff reviewed the analyses of the radiological consequences of a DBLOCA. The review included a summary review of the doses from the hypothetical DBLOCA and a specific review of the doses from containment leakage and leakage from ESF components outside containment that contribute to the total LOCA doses. The NRC staff's review also included (1) the methodology and results of calculations of the radiological consequences resulting from containment and ESF component leakage following a hypothetical LOCA; and (2) an assessment of the containment with respect to the assumptions and the values of input parameters for the dose calculations. The NRC staff's calculations are based on pertinent information in the FSAR and considered the NRC staff's evaluation of dose-mitigating ESFs. The NRC's acceptance criteria for the radiological consequences of a DBLOCA 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 whole body, or its equivalent to any part of the body, for the duration of the accident, and (2) 10 CFR Part 100, 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 6.4 and Appendices A and B of SRP Section 15.6.5.

2.9.7.2 Technical Evaluation

In its August 28, 2007, submittal, the licensee stated that the LOCA analysis was performed using the analytical methods and assumptions presented in the current licensing basis analysis with appropriate changes to reflect SPU conditions. The specific changes include: (1) revised source terms were used that reflected the core power uprate to 3612 MWt; (2) the RCS mass has been updated; and (3) updated modeling was used to calculate the whole body dose to CR operators from external sources which considers four sources. All other LOCA dose analysis assumptions are the same as in the current licensing basis calculation, which was previously reviewed and approved in Amendment No. 130 dated February 20, 2007.

The radiological consequence DBLOCA analysis is a deterministic evaluation based on the assumption of a major rupture of the primary RCS piping. The accident scenario assumes the deterministic failure of the ECCS to provide adequate core cooling, which results in a significant amount of core damage. This general scenario does not represent any specific accident sequence, but is representative of a class of severe core damage incidents. Such a scenario would be expected to require multiple failures of systems and equipment, and lies beyond the severity of incidents evaluated for design-basis transient analyses.

In the evaluation of the LOCA design-basis radiological analysis, the licensee included dose contributions from the following sources:

- Containment leakage
- ESF system component leakage

The licensee's analysis resulting in thyroid and whole body doses for each of the above release pathways was added together to determine the total projected thyroid and whole body doses for the LOCA. The licensee also calculated the beta radiation dose in the CR in a similar manner. During a DBLOCA, it is conservatively assumed that the fission product release to the containment will occur at the start of the accident and is likely to mix instantaneously and homogeneously throughout the free air volume of the primary containment.

2.9.7.2.1 Containment Sprays

The licensee's DBLOCA analysis credits the use of containment sprays to remove elemental and particulate iodine from the containment atmosphere. The methodology used to calculate particulate iodine removal remains unchanged from the current licensing basis, and is consistent with the SRP Section 6.5.2.

2.9.7.2.2 Containment Leakage

The total containment leakage for CPSES is 0.10 weight percent (wt%) per day, as governed by TSs. The containment maximum allowable leakage rate (L_a) is reduced by 0.5 wt% to 0.05 wt% per day at 24 hours for the duration of the accident, which is consistent with RG 1.195. The containment leakage is modeled as a ground level release to the environment.

2.9.7.2.3 Engineered Safety Feature Leakage

During a LOCA, a portion of the fission products released from the fuel will be carried to the containment sump via spillage from the RCS, by transport of activity from the containment atmosphere to the sump by containment sprays. During the initial phases of a LOCA, safety injection and the CSSs draw water from the RWST. Several minutes after accident initiation, valve realignment occurs to switch the suction water source for the ESF systems from the RWST to the containment sump. This recirculation flow causes contaminated water to be circulated through piping and components outside of the containment, where small amounts of system leakage could provide a path for the release of fission products to the environment. The licensee's current licensing basis uses a value of 2 gpm for the evaluation of the ESF leakage contribution to the LOCA dose.

To evaluate the radiological consequences of ESF leakage, the licensee used the deterministic approach as prescribed in RG 1.195. This approach assumes that 50 percent of the iodine originally present in the core is released from the fuel to mix instantaneously and homogeneously in the containment sump water.

The licensee assumed that the leakage of recirculating sump fluids commences at 10 minutes, which is the earliest time that the recirculation of contaminated fluids would begin. The licensee

conservatively used a flashing fraction of 0.1 for the ESF leakage calculation for the duration of the event. As a result, 10 percent of the entrained iodine activity in the ESF leakage effluent is assumed to be released to rooms housing the leaking components and then immediately swept away by the ventilation system and released to the atmosphere. In accordance with RG 1.195, the licensee assumed that the chemical form of the released iodine is 97 percent elemental and 3 percent organic.

2.9.7.2.4 Control Room Dose

The licensee calculated the CR whole body dose due to external factors using four parts. These parts include the following: (1) the activity that remains in containment; (2) the cloud of activity outside the CR; (3) streaming of the cloud of activity outside containment; and (4) the activity accumulated on the CR filters. The CR whole body dose was calculated for releases from containment leakage, ESF leakage and the containment pressure relief line prior to its isolation. The total whole body dose due to external sources is then added to the whole body dose due to activity inside the CR to determine the total whole body dose to operators in the CR. In response to NRC staff's RAI, letter dated January 31, 2008, the licensee provided a calculation description and results for this analysis. For part 1, the direct dose to the CR operators from activity dispersed in the containment building was calculated based on the geometric configuration of the CPSES Units using point kernel techniques.

For part 2, the whole body dose due to the cloud of activity outside the CR was determined by calculating the dose outside of the CR and applying an attenuation factor to model the dose reduction by the CR walls. The attenuation factors for each of the nuclides were calculated using discrete ordinates techniques for a location adjacent to the minimum thickness concrete envelope (1 foot 9 inches) and represent a set of conservative values for the remainder of the CR interior.

For part 3, the whole body CR dose due to streaming of radiation from the external cloud was calculated by applying a conservative correction factor to the whole body dose calculated for the external cloud of activity.

For part 4, the RADTRAD code was used to determine the build up of iodine activity on the CR filters for the containment and ESF leakage cases. For this calculation, it was conservatively assumed that all activity in the flow paths into the CR (filtered and unfiltered) was captured by the filters. (The activity collected on the filters from the containment pressure relief line is negligible and was not considered). The whole body dose from the activity on the CR filters was calculated using two-dimensional discrete ordinates techniques with the reference dose point location at an axial elevation approximately seven feet below the CR ceiling, approximating the location of personnel. The NRC staff has reviewed the licensee's information and determines that the CR whole body dose due to external factor is similar to what was previously calculated. The NRC staff finds this analysis to be conservative, has used industry standard calculation techniques, and is therefore acceptable.

2.9.7.3 Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of a DBLOCA and concludes that the licensee has adequately accounted for the

effects of the proposed SPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a DBLOCA, since the calculated whole-body and thyroid doses at the EAB and the LPZ outer boundary do not exceed the exposure guideline values of 10 CFR 100.11 and the calculated doses in the CR meet the requirements of GDC-19. The NRC staff's review has found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance in RG 1.195. The assumptions found acceptable to the NRC staff are presented in Tables 2.9-1 and 2.9-8. Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to the radiological consequences of a DBLOCA.

2.9.8 Radiological Consequences of Fuel Handling Accidents

2.9.8.1 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. Such accidents include the dropping of a single fuel assembly and handling tool or a heavy object onto other spent fuel assemblies. Such accidents may occur inside the containment, along the fuel transfer canal, and in the fuel building. The NRC staff's review included (1) the sequence of events, models, and assumptions used by the licensee for the calculation of radiological doses; (2) the adequacy of the ESFs provided for the purpose of mitigating potential accident doses; and (3) the containment ventilation system with respect to its function as a dose-mitigating ESF system, including the radiation detection system on the containment purge/vent lines for those plants that will vent or purge the containment during fuel handling operations. 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 CR under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident; (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 Part 100, insofar as it establishes requirements for assuring that radiological doses from postulated accidents will be acceptably low. Specific review criteria are contained in SRP Sections 6.4 and 15.7.4.

2.9.8.2 Technical Evaluation

In its August 28, 2007, submittal (Reference 3), the licensee stated that the FHA analysis was performed using the analytical methods and assumptions presented in the current licensing basis analysis with appropriate changes to reflect SPU conditions. The specific changes include: (1) revised source terms were used that reflected the core power uprate to 3612 MWt; (2) a fuel decay time of 50 hours was used for the analysis; and (3) The gap fractions from RG 1.25 (as modified by the direction NUREG/CR-5009) are used for the fraction of rods in the fuel assembly that are assumed to exceed the RG 1.195, Table 2, Footnote 7 criteria. All other FHA dose analysis assumptions are the same as in the current licensing basis calculation, which was previously reviewed and approved in Amendment No. 130 dated February 20, 2007.

The FHA analysis postulates that a spent fuel assembly is dropped during fuel handling and all of the fuel rods in the dropped assembly are conservatively assumed to experience fuel cladding damage, releasing the radionuclides within the fuel rod gap to the fuel pool or reactor cavity water. The affected assemblies are assumed to be those with the highest inventory of fission products in the core. Volatile constituents of the core fission product inventory migrate from the fuel pellets to the gap between the pellets and the fuel rod clad during normal power operations. The fission product inventory in the fuel rod gap of the damaged fuel rods is assumed to be instantaneously released because of the accident. Fission products released from the damaged fuel are decontaminated by passage through the overlaying water in the reactor cavity or SFP, depending on their physical and chemical form.

The licensee conservatively assumed no decontamination for noble gases and retention of all aerosol and particulate fission products in the overlying water. As prescribed in RG 1.195, the FHA is analyzed based on the assumption that 100 percent of the fission products released from the reactor cavity or SFP are released to the environment in 2 hours. The licensee did not credit filtration, holdup, or dilution of the released activity. Since the revised assumptions and inputs are identical for the FHA within containment and the FHA outside containment, the FHA outside containment is considered bounding.

RG 1.195 Appendix B gives a pool effective iodine decontamination factor (DF) of 200 as an acceptable assumption for the FHA, with a restriction that this value is acceptable for water depths of at least 23 feet and fuel internal rod pressures up to 1200 psig. If the depth of water is not at least 23 feet, the DF will have to be determined and found acceptable to the NRC staff on a case-by-case basis. Additionally, RG 1.195 allows the calculation of SFP DF on a case-by-case basis for rod internal pressures of greater than 1200 psig. The current licensing basis assumptions for the SFP DF, maximum rod internal pressure, and depth of water above fuel in the SFP are 160, 1500 psig, and 21 feet, respectively. These values were approved by the NRC through License Amendment No. 130.

In its August 28, 2007, letter, the licensee stated that a fuel decay time of 50 hours was used for the FHA dose analysis. In response to NRC staff's RAI, letter dated January 31, 2008, the licensee describe how it controls movement of the fuel prior to 50 hours. The required fuel decay time prior to fuel movement is governed by Technical Requirements Manual (TRM) TR 13.9.31, "Decay Time". This requirement is implemented using station refueling procedure RFO-102. Currently, the required fuel decay time prior to initiating fuel movement within the RV is 100 hours, per TR 13.9.31. This requirement is consistent with assumptions of the FHA analysis of record.

For SPU, the licensee has prepared a revision to the FHA analysis assuming shutdown occurs from steady-state operation at SPU conditions. In anticipation of future outage schedule improvements that may reduce the time necessary to prepare for fuel movement, the FHA analysis for the SPU was performed assuming fuel decay times of 50 and 75 hours. Revision of TRM TR 13.9.31 and RFO-102, to allow initiating fuel movement less than 100 hours after shutdown, is scheduled to occur prior to SPU implementation under 10 CFR 50.59 through plant procedures and programs. The actual change is bounded by the assumption of 50 hours reported within the SPULR.

In its August 28, 2007, letter, the licensee stated that for its FHA analysis, a small fraction of the fuel rods in the core may not satisfy the applicability statement for the RG 1.195 Table 2 gap inventory (listed below). For any fuel rods which are outside of the applicability range (6.3 kW/ft: 54 GWD/MTU), the licensee would revert back to RG 1.25 gap fractions, as adjusted by NUREG/CR-5009.

RG 1.195 Table 2 Footnote 7 states:

> The release fractions listed here have been determined to be acceptable for use with currently approved LWR fuel with a peak burnup up to 62,000 MWD/MTU provided that the maximum linear heat generation rate does not exceed 6.3 kW/ft peak rod average power for rods with burnups that exceed 54 GWD/MTU. As an alternative, fission gas release calculations performed using NRC-approved methodologies may be considered on a case-by-case basis. To be acceptable, these calculations must use a projected power history that will bound the limiting projected plant-specific power history for the specific fuel load.

The fission product gap inventories employed in the FHA are listed below:

Group	Fuel Rods Within 6.3/54 Applicability Range	Fuel Rods Outside 6.3/54 Applicability Range
I-131	0.08	0.12
Kr-85	0.10	0.30
Other Noble Gases	0.05	0.10
Other Iodines	0.05	0.10

Current regulatory guidance related to fission product gap inventories is provided within RG 1.195. This guidance supersedes that provided in RG 1.25 and NUREG/CR-5009. As stated in the applicability footnote (above), the staff would consider alternatives on a case-by-case basis. It is important to note that a lot of scatter exists within the limited database of fission gas measurements on high burnup rods. Power history, especially higher rod power levels at high burnup conditions, plays an important role in the amount of fission gas within the rod plenum. Hence, a lot of uncertainty exists in predicted gap fractions for fuel rods beyond the applicability range (6.3/54).

In support of the assumed FHA fission product gap inventory, the licensee provided American Nuclear Corporation (ANC) core physics predictions for an uprated equilibrium cycle. Extracting pin power and pin burnup histories, the licensee identified 24 fuel rods outside the applicability range. These fuel rods were located within 20 separate fuel assemblies with never more than 2 rods in any 1 assembly. The fuel rod radial power peaking factor for these fuel rods was below 1.20.

The FHA dose calculation assumes that 10 percent of the fuel rods in the limiting assembly exceed the applicability criteria. These fuel rods would employ the larger gap fractions noted above. Based upon the ANC calculations, this 10 percent assumption seems reasonable. The licensee has committed to validating the 10 percent assumption on a cycle-by-cycle basis as part of the reload safety analysis checklist.

For the FHA, the TS peak radial power peaking factor (FdH 1.65) is applied to all of the fuel rods. Based upon the ANC calculations, this assumption is overly conservative for any fuel rod outside the applicability range. While a degree of uncertainty exists in predicted gap inventory beyond the applicability range, it is believed that the combination of the larger gap inventories at the TS maximum peaking factor will compensate for this uncertainty.

Based upon the ANC calculation, cycle-by-cycle validation of the 10 percent fuel rods, and the use of larger gap inventories at the TS maximum peaking factor, the staff finds the FHA fission product gap inventory assumptions acceptable.

2.9.8.3 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 SPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated FHA since the calculated whole-body and thyroid doses at the EAB and the LPZ boundary are well within the exposure guideline values of 10 CFR 100.11 and GDC-61. The NRC staff also concludes that the CR meets the dose requirements of GDC-19 for DBAs. The NRC staff's review has found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance in RG 1.195. The assumptions found acceptable to the NRC staff are presented in Tables 2.9-1 and 2.9-9. Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to the radiological consequences of FHAs.

2.9.9 Radiological Consequences of Spent Fuel Cask Drop Accidents

2.9.9.1 Regulatory Evaluation

The NRC staff reviewed the analyses of the radiological consequences of the release of fission products from irradiated fuel in a spent fuel cask that is postulated to drop during cask handling operations for effects due to SPU. The NRC staff's review was conducted to verify various design and operations aspects of the system. The NRC staff's review included (1) determining a need for a design-basis radiological analysis; (2) sequence of events, models and assumptions used by the licensee for the calculation of the radiological doses; and (3) comparing the calculated doses to exposure guidelines to determine the acceptability of the EAB and LPZ outer boundary distances and to confirm the adequacy of ESFs provided for the purpose of mitigating potential doses from spent fuel cask drop accidents, including the effects on CR habitability.

The NRC's acceptance criteria for the radiological consequences of spent fuel cask drop accidents 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 whole body, or its equivalent to any part of the body, 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 Part 100, insofar as it establishes requirements for assuring that

radiological doses from postulated accidents will be acceptably low. Specific review criteria are contained in SRP Sections 6.4 and 15.7.5.

2.9.9.2 Technical Evaluation

The analyses of the radiological consequences of the release of fission products from irradiated fuel in a spent fuel cask that is postulated to drop during cask handling operations was not discussed in SE for Amendment No. 130. In its August 28, 2007, submittal, the licensee states that the spent fuel, SFP cooling and cleanup system, fuel storage and handling system, radioactive waste processing systems, and other systems that contain radioactivity are designed as follows to ensure adequate safety under normal and postulated accident conditions. Components are designed and located so that appropriate periodic inspection and testing can be performed. All areas of the plant are designed with suitable shielding for radiation protection based on anticipated radiation dose rates and occupancy as discussed in FSAR Section 12.3. Individual components that contain significant radioactivity are located in confined areas that are adequately ventilated through appropriate filtering systems. Radioactive waste management is discussed in detail in FSAR Chapter 11. The SFP cooling and cleanup system provides cooling to remove residual decay heat from the fuel stored in the SFP and is designed with redundancy and testability to ensure contained heat removal. A purification loop is provided to remove fission product activity. The SFP cooling and cleanup system is described in FSAR Section 9.1. The SFP is designed so that no postulated accident can cause excessive loss-of-coolant inventory. The primary plant ventilation system is designed to filter the exhaust from the fuel storage and handling, radioactive waste, and other systems that may contain radioactivity. The non-ESF exhaust units that satisfy GDC-61 are described in FSAR Section 9.4.

The piping connected to the fuel pool is designed so that a significant loss of fuel pool water does not occur because of a pipe rupture. Level instrumentation indicates a reduction in fuel pool water level, and redundant sources of fuel pool water are available.

The licensee states that the CPSES Fuel Handling Building crane satisfies NUREG-0554 single-failure proof requirements and is designed to the requirements of seismic Category I. As such, it can retain the maximum design load during an SSE and remain in place under all postulated seismic loadings. The crane is also provided with interlocks that prevent a fuel cask from being lifted more than 29.25 feet above-floor elevation or from passing over the new fuel storage area during the spent fuel cask mode of operation. The crane loads do not pass over the SFP in any mode of operation. The licensee states and the NRC staff agrees that based on this design approach, the radiological consequences of a spent fuel cask drop accident need not be evaluated.

2.9.9.3 Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of a spent fuel cask drop accident and concludes that the licensee has adequately accounted for the effects of the proposed SPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated spent fuel cask drop accident since the calculated whole-body and thyroid doses at the EAB and LPZ outer boundary are well within the

exposure guideline values of 10 CFR 100.11 and GDC-61. The NRC staff also concludes that the CR meets the dose requirements of GDC-19 for DBAs. Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to the radiological consequences of spent fuel cask drop accidents.

2.9.10 Steam Releases from Intact Steam Generators for Locked Rotor and MSLB Radiological Dose Analysis

The results of the evaluation for steam releases from the intact SGs for locked rotor and MSLB radiological dose analysis have been incorporated in to Sections 2.9.2 and 2.9.3 and a separate evaluation is not needed.

2.9.11 Radiological Consequences of Gas Decay Tank Rupture

2.9.11.1 Regulatory Evaluation

The NRC staff reviewed the analyses of the radiological consequences of the release of fission products from a postulated gas decay tank rupture. The NRC staff's review was conducted to verify various design and operations aspects of the system. The NRC staff's review included (1) determining a need for a design-basis radiological analysis; (2) sequence of events, models and assumptions used by the licensee for the calculation of the radiological doses; and (3) comparing the calculated doses to exposure guidelines to determine the acceptability of the EAB and LPZ outer boundary distances and to confirm the adequacy of ESFs provided for the purpose of mitigating potential doses from a gas decay tank rupture, including the effects on CR habitability. The NRC's acceptance criteria for the radiological consequences of a gas decay tank rupture 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 whole body, or its equivalent to any part of the body, 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 Part 100, insofar as it establishes requirements for assuring that radiological doses from postulated accidents will be acceptably low. Specific review criteria are contained in SRP Sections 6.4 and 11.3.

2.9.11.2 Technical Evaluation

In its August 28, 2007, submittal, the licensee stated that the gas decay tank rupture analysis was performed using the analytical methods and assumptions presented in the current licensing basis analysis with appropriate changes to reflect SPU conditions. The specific changes include revised source terms that reflected the core power uprate to 3612 MWt. All other gas decay tank rupture dose analysis assumptions are the same as in the current licensing basis calculation, which was previously reviewed and approved in Amendment No. 130 dated February 20, 2007.

The gas decay tank rupture is defined as an unexpected and uncontrolled release of radioactive xenon and krypton fission product gases stored in a waste decay tank as a consequence of a failure of a single gas decay tank or associated piping.

This event is not listed as an accident in RG 1.195, but is discussed in Branch Technical Position (BTP) 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," where the appropriate accident-specific dose acceptance criteria are given. The offsite dose criterion is that the calculated whole body dose is substantially below the 10 CFR 100.11 limits (i.e., 0.5 rem). In its reanalysis the licensee used the assumptions contained in the current licensing basis as discussed in CPSES FSAR.

2.9.11.3 Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of a gas decay tank rupture and concludes that the licensee has adequately accounted for the effects of the proposed SPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated gas decay tank rupture since the calculated whole-body and thyroid doses at the EAB and LPZ outer boundary are well within the exposure guideline values of 10 CFR 100.11 and GDC-61. The NRC staff also concludes that the CR meets the dose requirements of GDC-19 for DBAs. The assumptions found acceptable to the NRC staff are presented in Table 2.9-1. Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to the radiological consequences of a gas decay tank rupture.

2.9.12 Radiological Consequences of Liquid Waste Tank Rupture

2.9.12.1 Regulatory Evaluation

The NRC staff reviewed the analyses of the radiological consequences of the release of fission products from a postulated liquid waste tank rupture. The NRC staff's review was conducted to verify various design and operations aspects of the system. The NRC staff's review included (1) determining a need for a design-basis radiological analysis; (2) sequence of events, models and assumptions used by the licensee for the calculation of the radiological doses; and (3) comparing the calculated doses to exposure guidelines to determine the acceptability of the EAB and LPZ outer boundary distances and to confirm the adequacy of ESFs provided for the purpose of mitigating potential doses from a liquid waste tank rupture, including the effects on CR habitability. The NRC's acceptance criteria for the radiological consequences of a liquid waste tank rupture 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 whole body, or its equivalent to any part of the body, 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 Part 100, insofar as it establishes requirements for assuring that radiological doses from postulated accidents will be acceptably low. Specific review criteria are contained in SRP Sections 6.4 and 15.7.3.

2.9.12.2 Technical Evaluation

In its August 28, 2007, submittal, the licensee stated that the liquid waste tank rupture analysis was performed using the analytical methods and assumptions presented in the current licensing basis analysis with appropriate changes to reflect SPU conditions. The specific changes

include revised source terms that reflected the core power uprate to 3612 MWt. All other liquid waste tank rupture dose analysis assumptions are the same as in the current licensing basis calculation, which was previously reviewed and approved in Amendment No. 130 dated February 20, 2007.

The liquid waste tank rupture is defined as the uncontrolled atmospheric release from the 30,000 gallon floor drain tank due to the postulated rupture of the tank. This tank is assumed to be 80 percent full of reactor coolant. The entire contents of the tank are assumed to be released to the building. The activity released from the tank is assumed to be released to the atmosphere over a 2-hour period at ground level.

This event is not listed as an accident in RG 1.195, but is discussed in SRP 15.7.3, “Postulated Radioactive Releases Due to Liquid-Containing Tank Failures.” In its reanalysis, the licensee used the assumptions contained in the current licensing basis as discussed in CPSES FSAR. The offsite dose criterion remains unchanged from the current licensing basis.

2.9.12.3 Conclusion

The NRC staff has evaluated the licensee’s revised accident analyses for the radiological consequences of a liquid waste tank rupture and concludes that the licensee has adequately accounted for the effects of the proposed SPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated liquid waste tank rupture since the calculated whole-body and thyroid doses at the EAB and LPZ outer boundary are well within the exposure guideline values of 10 CFR 100.11 and GDC-61. The NRC staff also concludes that the CR meets the dose requirements of GDC-19 for DBAs. Therefore, the NRC staff finds the licensee’s proposed SPU acceptable with respect to the radiological consequences of a liquid waste tank rupture.

2.9.12.4 Radiological Consequence Analysis Conclusion

The NRC staff has evaluated the licensee’s revised accident analyses performed in support of the proposed SPU and concludes that the licensee has adequately accounted for the effects of the proposed SPU. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of postulated DBAs since, as set forth above, the calculated total effective dose equivalent (TEDE) at the EAB, at the LPZ outer boundary, and in the CR meet the exposure guideline values specified in 10 CFR 50.67 and GDC-19, as well as applicable acceptance criteria denoted in SRP Section 15.0.1. Therefore, the NRC staff finds the licensee’s proposed SPU acceptable with respect to the radiological consequences of DBAs.

Table 2.9-1
CPSES, Units 1 and 2, Licensee Calculated Radiological Consequences

Release Pathway	Location	Dose Type	Dose (rem)	Acceptance Criterion (rem)
MSLB Pre-Accident Iodine Spike	EAB	Thyroid	1.2E+00	300
		Whole-Body	2.5E-03	25
	LPZ	Thyroid	6.7E-01	300
		Whole-Body	1.1E-03	25
	CR	Thyroid	1.1E+00	50
		Whole-Body	1.3E-03	5
		β-Skin	3.6E-02	50
MSLB Accident-Initiated Iodine Spike	EAB	Thyroid	1.5E+00	30
		Whole-Body	4.9E-03	2.5
	LPZ	Thyroid	3.1E+00	30
		Whole-Body	5.4E-03	2.5
	CR	Thyroid	3.1E+00	50
		Whole-Body	1.5E-03	5
		β -Skin	3.7E-02	50
Locked Rotor Accident	EAB	Thyroid	2.7E+00	30
		Whole-Body	1.7E-01	2.5
	LPZ	Thyroid	5.1E+00	30
		Whole-Body	5.8E-02	2.5
	CR	Thyroid	3.8E+00	50
		Whole-Body	2.0E-01	5
		β -Skin	2.6E+00	50
Control Rod Ejection Accident: Containment Release	EAB	Thyroid	2.0E+01	75
		Whole-Body	8.2E-02	6.3
	LPZ	Thyroid	2.8E+01	75
		Whole-Body	4.3E-02	6.3
	CR	Thyroid	2.3E+01	50
		Whole-Body	2.6E-02	5
		β -Skin	4.1E-01	50

Table 2.9-1 (Cont.)
CPSES, Units 1 and 2, Licensee Calculated Radiological Consequences

Release Pathway	Location	Dose Type	Dose (rem)	Acceptance Criterion (rem)
Control Rod Ejection Accident: Secondary Release	EAB	Thyroid	4.2E+00	75
		Whole-Body	4.2E-01	6.3
	LPZ	Thyroid	7.9E+00	75
		Whole-Body	1.5E-01	6.3
	CR	Thyroid	5.8E+00	50
		Whole-Body	5.0E-01	5
		β -Skin	6.3E+00	50
Letdown Line Break	EAB	Thyroid	6.2E+00	30
		Whole-Body	5.0E-02	2.5
	LPZ	Thyroid	1.0E+00	30
		Whole-Body	7.0E-03	2.5
	CR	Thyroid	7.0E-01	50
		Whole-Body	2.0E-02	5
		β -Skin	5.0E-01	50
SGTR Pre-Accident Iodine Spike	EAB	Thyroid	4.0E+01	300
		Whole-Body	1.4E-01	25
	LPZ	Thyroid	6.0E+00	300
		Whole-Body	3.0E-02	25
	CR	Thyroid	1.7E+01	50
		Whole-Body	1.0E-01	5
		β -Skin	2.4E+00	50
SGTR Accident-Initiated Iodine Spike	EAB	Thyroid	2.6E+01	30
		Whole-Body	1.8E-01	2.5
	LPZ	Thyroid	4.0E+00	30
		Whole-Body	3.0E-02	2.5
	CR	Thyroid	3.6E+00	50
		Whole-Body	1.0E-01	5
		β -Skin	2.4E+00	50

Table 2.9-1 (Cont.)
CPSES, Units 1 and 2, Licensee Calculated Radiological Consequences

Release Pathway	Location	Dose Type	Dose (rem)	Acceptance Criterion (rem)
Loss-of-Coolant Accident	EAB	Thyroid	5.9E+01	300
		Whole-Body	7.0E-01	25
	LPZ	Thyroid	4.4E+01	300
		Whole-Body	2.5E-01	25
	CR	Thyroid	4.0E+01	50
		Whole-Body	1.2E+00	5
		β -Skin	1.3E+01	50
Fuel Handling Accident	EAB	Thyroid	2.6E+1	75
		Whole-Body	1.4E-01	6.3
	LPZ	Thyroid	3.9E+0	75
		Whole-Body	2.1E-2	6.3
	CR	Thyroid	4.2E+00	50
		Whole-Body	1.8E-01	5
		β -Skin	5.2E+00	50
Gas Decay Tank Rupture	EAB	Whole-Body	1.9E-01	0.5
	LPZ	Whole-Body	2.8E-02	0.5
	CR	Whole-Body	3.0E-01	5
		β -Skin	3.2E+01	50
Liquid Waste Tank Rupture	EAB	Thyroid	2.1E+00	6
		Whole-Body	3.8E-03	0.5
	LPZ	Thyroid	3.2E-01	6
		Whole-Body	5.6E-04	0.5
	CR	Thyroid	3.8E+01	50
		Whole-Body	3.5E-03	5
		β -Skin	2.2E-02	50

Table 2.9-2
CPSES, Units 1 and 2, Atmospheric Dispersion Factors (χ/Qs)

Receptor / Duration	**χ/Q (sec/m^3)**
Control Room, from Containment Leakage / Atmospheric Relief Valves	
0 - 8 hours	3.04E-03
8 - 24 hours	1.82E-03
24 - 96 hours	6.08E-04
96 - 720 hours	1.4E-04
Control Room, from ESF Equipment Leakage Outside Containment	
0 - 8 hours	2.96E-03
8 - 24 hours	1.86E-03
24 - 96 hours	6.51E-04
96 - 720 hours	1.78E-04
EAB	
0 - 2 hours	1.6E-04
LPZ	
0 - 8 hours	2.4E-05
8 - 24 hours	1.6E-05
24 - 96 hours	6.2E-06
96 - 720 hours	1.7E-06

Table 2.9-3
CPSES, Units 1 and 2, Control Room Data and Assumptions

CR effective volume	423,032 ft^3
Normal CR intake flow rate prior to isolation Unfiltered inleakage	3300 cfm 27 cfm
Air intake flow rate (filtered) (emergency recirculation mode)	800 cfm
Air intake flow rate (emergency ventilation mode)	4180 cfm
Emergency Ventilation System Recirculation flow rate (emergency recirculation mode)	6320 cfm
Emergency Ventilation System Recirculation flow rate (emergency ventilation mode)	3020 cfm
Response time for CR to isolate upon receipt of Control Room Ventilation Radiation Monitor Alarm Signal	1 min
Filter Efficiencies for the Emergency Ventilation System	99% elemental 99% aerosol 99% organic
Control building wall thickness Control room ceiling/roof thickness	2 ft concrete 3 ft concrete
CR occupancy factors 0 - 24 hours 24 - 96 hours 96 - 720 hours	 1.0 0.6 0.4
Breathing rate for CR dose analyses	3.5E-04 m^3/sec

Table 2.9-4
CPSES, Units 1 and 2, Data and Assumptions for the MSLB Accident

Primary-to-secondary leak rate (to intact SGs)	1 gpm
Secondary iodine TS limit	0.1 µCi/gm DE I-131
RCS limit for normal operation Gross gamma Iodine	 500 µCi/gm DE XE-133 1.0 µCi/gm DE I-131
RCS limit for pre-accident iodine spike	60 µCi/gm DE I-131
Coincident spike appearance rate multiplier	500
LOOP	Assumed to occur at accident initiation
Release points: Affected SG Intact SG	 Turbine building SG ARVs
Iodine partition factor for affected SG	1.0
Iodine partition factor for intact SGs	0.01
Primary-to-secondary leakage Affected SG Intact SG Total	 500 gpd 0.6528 gpm 1 gpm
SG liquid mass	71,000 lbm
RCS liquid mass Maximum Minimum	 570,000 lbm 440,000 lbm
Duration of SG release: Affected SG Intact SG	 25.75 hours 11 hours
Steam release from affected SG Initial inventory Primary-to-secondary leak	 35,200 lbm/min (0 - 5 min) 2.9 lbm/min (0 – 25.75 hrs)
Steam release from intact SGs 0 - 2 hours 2 - 11 hours	 4.348E+05 lbm (Unit 1) 4.05E+05 lbm (Unit 2) 1.235E+06 lbm (Unit 1) 1.228E+06 lbm (Unit 2)

Table 2.9-5
CPSES, Units 1 and 2, Data and Assumptions for the LRA

Fuel clad failure	15%
RCS iodine limit for normal operation	1.0 µCi/gm DE I-131
Secondary iodine TS limit	0.1 µCi/gm DE I-131
Radial peaking factor	1.65
Primary-to-secondary leak rate	1 gpm
Release points	SG ARV
Chemical form of iodine released from the SGs to the environment	3% organic iodide 97% elemental iodine
Fraction of fission product inventory in gap I-131 Iodines Noble gases	 0.08 0.05 0.05
Iodine partition fraction	0.01
Release duration	8 hours (RHR placed in service)
Total mass of steam to atmosphere from intact SGs 0 - 2 hours 2 - 11 hours	 440,000 lbm (Unit 1) 402,000 lbm (Unit 2) 1,277,000 lbm (Unit 1) 1,275,000 lbm (Unit 2)
Initial SG liquid mass	71,000 lbm

Table 2.9-6
CPSES, Units 1 and 2, Data and Assumptions for the CREA

Containment free air volume	3.031E+06 ft^3
Fuel clad failure	15%
Fraction of core inventory in gap Noble gasses Iodine	 10% 10%
Core fuel melt	0.375%
Release fractions for melted fuel Containment release Noble gasses Iodines Reactor coolant release Noble gasses Iodines	 100% 25% 100% 50%
Chemical form of iodine released from the SG to the environment	3% organic iodide 97% elemental iodine
Total primary-to-secondary leakage through all SGs	1 gpm
Duration of steam releases	11 hours
Total mass of steam to atmosphere from intact SGs 0 - 2 hours 2 - 11 hours	 440,000 lbm (Unit 1) 402,000 lbm (Unit 2) 1,277,000 lbm (Unit 1) 1,275,000 lbm (Unit 2)
Release point	SG ARV

Table 2.9-7
CPSES, Units 1 and 2, Data and Assumptions for the SGTR Accident

Primary-to-secondary leak rate	1 gpm
Secondary iodine TS limit	0.1 µCi/gm DE I-131
RCS limit for normal operation Gross gamma Iodine	 500 µCi/gm DE XE-133 1.0 µCi/gm DE I-131
RCS limit for pre-accident iodine spike	60 µCi/gm DE I-131
Coincident spike appearance rate multiplier	335
Iodine spike duration	6 hours
Secure release from affected SG	49 minutes (from reactor trip)
Secure release from intact SGs	11 hours (RHR initiated)
Iodine partition factor	0.01
Condenser partition factor	0.15
Duration of release to environment Intact SGs Affected SG	 0 – 11 hours 0 – 3237 seconds
Initial affected SG mass	71,000 lbm
Initial Intact SG mass	213,000 lbm

Table 2.9-8
CPSES, Units 1 and 2, Data and Assumptions for the LOCA

Containment free air volume	3.031E+06 ft^3
Containment leak rate	weight percent per day
Containment leak rate reduction	50% after 24 hours
Iodine chemical form in containment atmosphere	91% elemental iodine 4% organic iodine 5% particulate iodine
Iodine chemical form in the sump	97% elemental 3% organic
Containment sump pH	≥ 7
Containment Spray System (CSS) effective operation period	74.3 sec for full flow
Elemental iodine removal coefficient	10 hr-1 until a DF of 100 then 0
Particulate iodine removal coefficient	11.4 hr-1 until a DF of 50 1.14 hr-1 at a DF of > 50
Duration of elemental iodine removal effectiveness	2.518 hr (DF of 100 attained)
Duration of particulate iodine removal effectiveness	2.03 hr (DF of 50 attained) 4.0 hr (sprays assumed to be terminated)
CSS containment coverage volume	1,705,945 ft^3
ECCS leakage outside containment	2 gpm
Minimum available RWST volume	4.053E+05 gallons (1.543E+09 cc)

Table 2.9-9
CPSES, Units 1 and 2, Data and Assumptions for the FHA

Fuel clad damage	All rods in 1 assembly
Gap fractions I-131 Kr-85 Other noble gases Other iodines	 8% 10% 5% 5%
Pool DF Noble gases Iodines	 1 160 (effective DF)
Release point	Ground level
Decay time	100 hours
Radial peaking factor	1.65
Duration of release	2 hours

2.10 Health Physics

Health Physics is not reviewed for an SPU based on the "Power Uprate Review Guidance," contained in the memorandum from C. Jackson (NRC) to D. Collins (NRC), dated February 6, 2006 (ADAMS Accession No. ML060400439). Hence, the NRC staff did not perform a review of the information provided by the licensee in this section.

2.11 Human Performance

2.11.1 Regulatory Evaluation

The staff reviewed the licensee's human factors evaluation to confirm that changes made to implement the proposed SPU will not adversely affect operator performance. The staff reviewed changes to operator actions, human-system interfaces, procedures, and training identified by the licensee as needed for the proposed SPU. The NRC's acceptance criteria for human factors are based on GDC-19, 10 CFR 50.120, 10 CFR 55.59, and the guidance in GL 82-33. Specific review criteria are contained in NUREG-0800 (Revision 1), SRP Chapter 18.0.

2.11.2 Technical Evaluation

The NRC staff has developed a standard set of topics for the human factors assessment of power uprates, i.e., Section 2.9 of Review Standard RS-001 (Reference 1). The licensee has addressed these topics in its submittal. The following is the licensee's description of these topics and results of the staff evaluation.

2.11.2.1 Emergency and Abnormal Operating Procedures

This section includes a summary of the licensee's assessment of how the proposed SPU will change the plant EOPs and abnormal operating procedures (AOPs), and the staff's evaluation of that assessment.

The licensee stated in its application dated August 28, 2007 (Reference 3), that the SPU will result in changes to the applicable AOPs to address changes in setpoints, alarm response setpoints, and physical plant changes as a result of the proposed SPU. The licensee also stated that the applicable EOPs may involve changes to setpoints. However, no changes are required to the procedure steps and mitigation actions. The licensee plans to implement the changes to the AOPs and EOPs and provide the operators with appropriate classroom and/or simulator training prior to SPU implementation.

The NRC staff requested the licensee to identify all changes to the EOPs and determine whether any of the changes will affect the time required or the time available to perform EOP operator actions. In the supplemental response dated February 21, 2008 (Reference 10), the licensee confirmed that there is no impact on the time required or the time available to perform EOP operator actions as a result of the proposed SPU.

The staff concludes that the effects of the proposed SPU on the AOPs and EOPs have been identified and incorporated, while retaining the current operator actions and mitigation strategies unchanged. The changes being made to the AOPs and EOPs will be reflected in the operator training program prior to SPU implementation.

2.11.2.2 Operator Actions Sensitive to Power Uprate

This section includes the review of any new operator actions needed as a result of the proposed SPU and changes to any current operator actions related to EOPs or AOPs that will occur as a result of the proposed SPU.

The licensee in its application dated August 28, 2007 (Reference 3), stated that no changes would be required to the EOP steps and mitigation actions as a result of the proposed SPU. CPSES AOPs were expected to have minor changes to address additional heat loads generated by the main generator and auxiliaries due to proposed SPU. The licensee also stated that the proposed procedure changes would not significantly impact operator actions.

The staff requested clarification on operator actions that are currently credited for DBA in CPSES's FSAR that could be affected by the proposed SPU. The licensee was specifically requested to describe these particular operator actions and/or the associated controls, displays, or alarms. Additionally, the licensee was requested to address any changes to the time required or the time available for those actions. The licensee in its response dated February 21, 2008 (Reference 10), indicated the following two changes for DBA operator actions:

- "Steam Generator Tube Rupture: The steam generator tube rupture analyses model operator actions to isolate the ruptured steam generator (SG) [including isolation of the failed-open ARV (atmospheric relief valve) for the mass release case], cooldown the RCS (reactor coolant system) using the intact SG ARVs,

depressurize the RCS using the pressurizer PORVs (power operated relief valves), and terminate SI (safety injection) flow. The times credited are presented in Table 2.8.5.6.2-1 of WCAP-16840 (Reference 2). The times for isolation of the ruptured SG [including isolation of the failed-open ALRV (*stet* ARV) for the mass release case], initiation of the RCS cooldown, and initiation of the RCS depressurization were not changed for the SPU program. The timing of the Safety Injection (SI) termination was changed for the uprate analysis. For the uprate analyses, the modeling was updated to model the termination of all SI injection flow to the RCS two minutes (previously 1 minute) after the end of depressurization. The break flow was then allowed to coast down to termination assuming no additional operator actions. This has been shown to be conservative compared to the pre-uprate modeling and supports the 'Operator Action Time to Initiate Safety Injection Termination' entry in Table 2.8.5.6.2-1 of WCAP-16840-P (Reference 2)."

- "Inadvertent ECCS: The safety grade alarm (SI signal) is assumed to be initiated concurrent with the inadvertent SI signal. A simulator exercise was performed in accordance with [CPSES] validation guidelines to assure that the assumed response times were reasonable. The simulator was set up to replicate many of the conservative assumptions of the FSAR Chapter 15 analyses, including the failure of automatic operation of the pressurizer PORVs, the Steam Dump System, and the automatic operation of the steam generator atmospheric relief valves (ARVs). Verifying the RCS average temperature is trending to 557 degrees F and taking manual control of the RCS average temperature occurred shortly after entry into the emergency procedures well within the assumed 7.5 minutes. Through the continuation of the simulator exercise, the crew was able to step through the procedures and secure ECCS well within the 13 minutes assumed in the analyses (close to 10 minutes). All communication protocols and management expectations for conduct of operations were met during the exercise."

The staff has reviewed the licensee's supplemental information for the changes involving DBA operator actions that will be impacted by the proposed SPU. The staff finds these operator actions acceptable because the actual operator actions have not changed and were found by the licensee's updated analysis to be conservative regarding time available to accomplish the actions. The operator actions have been re-validated by the licensee using the training simulator. Although it is implied that only one operating crew was used, the staff finds this limited validation acceptable because the operator actions remain unchanged in terms of the associated tasks. The licensee's analysis also confirms the original validation described in the FSAR Chapter 15 analysis and is supported by the continuing training of the operators.

2.11.2.3 Changes to Control Room Controls, Displays, and Alarms

This section includes the review of any changes the proposed SPU will have on the operator interfaces for CR controls, displays, and alarms.

In its application dated August 28, 2007 (Reference 3), the licensee stated that changes to the CPSES, Units 1 and 2 CR controls and displays would not be extensive and will include

rebanding indicators and rescaling loops for identified instrumentation. The licensee also stated that changes to several control board and computer alarms will be made along with limited changes to plant control systems. A list of the changes to the CR controls, alarms, and displays was provided in the amendment request. Specific changes to instrumentation associated with turbine first stage pressure will require scaling changes for various NSSS inputs such as AMSAC, Permissive P7, rod control, block auto rod withdrawal, and steam dump control. The proposed SPU also involves other balance of plant modifications such as the main high pressure turbine upgrade, main transformer replacements, heater drain pump upgrades, iso-phase bus duct cooling modifications, and turbine-generator component cooling modifications. The licensee further stated that the hardware modifications may involve associated control system modifications and will be evaluated for human factors as part of normal plant procedures in the design change process. Training will be provided to CPSES operators related to the SPU modifications and resulting control board and procedure changes. The CPSES operators will also be provided station modification review packages as well as classroom and simulator training, where appropriate. The initial plant startup after implementation of SPU will be performed as an infrequent evolution and will be controlled by a power ascension testing program.

The staff requested the licensee to identify any control systems that will be modified and to describe any resultant effects on operator actions, timing, or operator interfaces. The licensee provided the following supplemental information in its letter dated February 21, 2008 (Reference 10):

- Main Turbine: The CPSES, Units 1 and 2 high pressure turbines will be replaced in order to pass the additional volumetric steam flow. Turbine digital controls and thyristor voltage regulator settings will be revised for uprate conditions.

- Condensate and Feedwater Systems: Higher condensate pump flow rate and additional head loss in the condensate and feedwater piping will result in lower suction pressure at the MFP. To preserve operating margin to alarms and automatic actions on low-MFP suction pressure, the setpoints and instrumentation associated with MFP NPSH protection, condensate polisher bypass, and feedwater heater bypass will be changed.

- Extraction Steam and Heater Drains: There will be slight increases in the temperatures, pressures, and flows in the extraction steam piping and in the various heater drains. Modifications to increase the capacity of the heater drain pumps will be installed to satisfy uprate heater drain flow requirements.

- Main Generator: The main generator electrical output will increase by approximately 49 MWe (CPSES, Unit 1) and 37 MWe (CPSES, Unit 2). Each main generator will be re-rated from 1350 to 1410 MVA with an allowable power factor of 0.9. The hydrogen coolers and exciter coolers will be replaced to provide additional cooling capacity during the summer months.

- Iso-Phase Bus Ducts/Main Transformers: To transfer the power from the main generator to the grid the design capacity of the iso-phase bus duct system will be increased. The bus duct cooling fan/coil capacity will be increased to provide

additional cooling. The main transformers are currently operating under administrative voltage limits. The main transformers have been evaluated and found acceptable at SPU conditions with the current administrative limits. The main transformers are scheduled to be replaced due to their age and to enhance their MVAR support capability. CPSES, Unit 2 transformers are scheduled to be replaced in 2009 and CPSES, Unit 1 in 2010, after one cycle of SPU operation.

The licensee stated that the above modifications "will not impact control systems which affect plant operator actions, timing, or operator interfaces." Additionally, the licensee stated that there are no controls, displays, or alarms being upgraded from analog to digital instrumentation as a result of the proposed SPU.

The purpose of this section is to assure that the licensee has adequately considered the effects of the proposed SPU regarding operator interfaces for CR controls, displays, and alarms. The licensee has stated that all modifications to the CR and associated operator training on these changes will take place prior to SPU implementation. The staff finds the proposed changes acceptable based upon the licensee implementing its design change process to address the SPU-related changes in the CR and the corresponding operator training and simulator modifications prior to SPU implementation. The staff also concludes that the proposed changes do not present any adverse effects to the operators' functions in the CR and will not alter existing requirements for the CR as stated in GDC-19.

2.11.2.4 Changes on the Safety Parameter Display System

This section includes the review of the changes to the safety parameter display system (SPDS) resulting from the proposed SPU and how the licensee will make the operators aware of the proposed SPDS changes.

In its application dated August 28, 2007 (Reference 3), the licensee stated that no significant SPDS changes are anticipated as a result of the proposed SPU. The licensee plans to review and revise critical safety function status trees as necessary for changes to setpoints and decision points. The licensee also stated that "any changes identified to the SPDS will be captured through the normal update process, modification process, and interdepartmental reviews."

The staff requested the licensee to confirm if there were changes required to the SPDS, describe the changes, and state how these changes would affect the operators' ability to monitor critical safety functions. The licensee in its response dated February 21, 2008 (Reference 10), indicated that the SPU could affect the following SPDS display variables available to the operator through the plant computer system:

- Power Range Power
- Intermediate Range Power
- Intermediate Range Start-up Rate
- Source Range High Voltage
- Source Range Start-up Rate
- Neutron Flux Wide Range
- Neutron Flux Source Range

- Core Exit Temperature
- RCS Margin to Saturation
- RCP Breaker Status
- RVLIS [reactor vessel level indicating system] Indication - Bottom Level
- Steam Generator Levels
- Steam Generator Pressures
- AFW Flows
- RCS Cold Leg Temperature
- RCS Hot Leg Temperature
- RCS Pressurizer Pressure
- RCS Pressure
- Containment Pressure
- Containment Water Level
- Containment Radiation
- Pressurizer Level
- Reactor Vessel Level

The licensee also stated that critical safety function status trees reflecting the above identified parameters were considered during the design change process for the proposed SPU. After further review by the licensee, the proposed SPU is not expected to impact the displays, calculations, or functional requirements of the SPDS. However, the licensee did identify that several warning limits on SPU-affected parameters of the SPDS will require modification similar to control board banding modifications once the design has been finalized. These particular changes are also not expected to impact operator cognizance or the operator's ability to monitor safety functions.

The staff reviewed the proposed changes to the SPDS as described by the licensee and concluded that the proposed changes to the SPDS are acceptable based on the statements by the licensee that the changes will not be extensive and that the changes will not impact the operator's ability to monitor safety functions.

2.11.2.5 Control Room Plant Reference Simulator and Operator Training

This section evaluates any changes to the operator training program and the plant-referenced CR simulator resulting from the proposed SPU and the implementation schedule for making the changes.

The licensee in its application dated August 28, 2007 (Reference 3), stated that CPSES will employ a systematic approach to its Licensed/Non-Licensed Operator training programs ensuring that adequate training is provided for plant modifications prior to SPU implementation. The licensee also stated that the operator training on all SPU-related changes to procedures, operator actions, and CR changes (including the SPDS) will be provided prior to the SPU implementation in 2008 for CPSES, Unit 1 and 2009 for CPSES, Unit 2. The operator training will focus on the SPU modifications and impact of the SPU on plant system operating conditions following implementation of the SPU. Classroom and simulator training will be utilized to provide the operators the ability to demonstrate understanding of the integrated plant response

due to the SPU. Additional power ascension training will cover the testing and monitoring that will be performed during power ascension to the uprated power level.

The staff concludes that the changes proposed by the licensee to the operator training program, including simulator training, are acceptable for the proposed SPU. The staff also finds that these changes are being made in accordance to 10 CFR 50.120.

2.11.3 Conclusion

The NRC staff has reviewed the licensee-identified changes to operator actions, human-system interfaces, procedures, and training required for the proposed SPU and concludes that the licensee has: (1) appropriately accounted for the effects of the proposed SPU on the available time for operator actions and (2) taken appropriate actions to ensure that operator performance is not adversely affected by the proposed SPU. The NRC staff further concludes that the licensee will continue to meet the requirements of GDC-19, 10 CFR 50.120(b)(2)(i) and 10 CFR 50.120(b)(3), and 10 CFR Part 55.59(c)(3)(AA)(iii) following implementation of the proposed SPU. Therefore, the NRC staff finds the licensee's proposed SPU acceptable regarding the human factors aspects of the required system changes.

2.12 Power Ascension and Testing Plan

Power ascension and testing plan is not reviewed for an SPU based on the "Power Uprate Review Guidance," contained in the memorandum from C. Jackson (NRC) to D. Collins (NRC), dated February 6, 2006 (ADAMS Accession No. ML060400439). Hence, the NRC staff did not perform a review of the information provided by the licensee in this section.

2.13 Risk Evaluation

Health Physics is not reviewed for an SPU based on the "Power Uprate Review Guidance," contained in the memorandum from C. Jackson (NRC) to D. Collins (NRC), dated February 6, 2006 (ADAMS Accession No. ML060400439).

3.0 FACILITY OPERATING LICENSES AND TECHNICAL SPECIFICATION CHANGES

To achieve the SPU, the licensee proposed the following changes to the Facility Operating Licenses and TSs for CPSES, Units 1 and 2.

3.1 Facility Operating Licenses

To achieve the SPU, the licensee has proposed changes to the Facility Operating Licenses NPF-87 and NPF-89, Paragraph 2.C.(1): the maximum power level is changed to authorize operation at reactor core power levels not in excess of 3612 MWt.

Accordingly, Paragraph 2.C.(1) of Facility Operating License NPF-87 for CPSES, Unit 1 is changed to read as follows:

(1) Maximum Power Level

Luminant Generation Company LLC is authorized to operate the facility at reactor core power levels not in excess of 3458 megawatts thermal through Cycle 13 and 3612 megawatts thermal starting with Cycle 14 in accordance with the conditions specified herein.

In addition, Paragraph 2.C.(1) of Facility Operating License NPF-89 for CPSES, Unit 2 is changed to read as follows:

(1) Maximum Power Level

Luminant Generation Company LLC is authorized to operate the facility at reactor core power levels not in excess of 3458 megawatts thermal through Cycle 11 and 3612 megawatts thermal starting with Cycle 12 in accordance with the conditions specified herein.

Based on the evaluation in Section 2.0 of the SE, the NRC staff finds the changes acceptable.

3.2 Technical Specifications

Technical Specification 1.1, Definitions, “RATED THERMAL POWER”, is changed from 3458 MWT to 3612 MWt (starting with Cycle 14 for CPSES, Unit 1 and Cycle 12 for CPSES, Unit 2).

Based on the evaluation in Section 2.0 of the SE, the NRC staff finds the change acceptable.

4.0 REGULATORY COMMITMENTS

The licensee has made the following regulatory commitments:

1. The 4.5 percent uprate conditions will be considered as part of the restoration of the containment coating qualifications supporting resolution of GSI-191, Containment Sumps.

2. A small load reduction test of at least 50 MWe will be performed to confirm the expected integrated response of the following automatic control systems at SPU conditions;

   - Rod Control System
   - Steam Generator Water Level Control System
   - Pressurizer Level Control System

   This load reduction test, along with routine startup and surveillance testing, post-modification testing, and power ascension testing and monitoring will provide the bases for confirmation of predicted and extrapolated system dynamic

behavior. The results of this testing and monitoring, combined with SPU analyses, will be used to confirm that the plant systems, including the above identified automatic control systems are capable of performing safely and reliably in the uprated condition.

The NRC staff finds that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitment(s) 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

Inspection Procedure (IP) 71004 "Power Uprates," describes the inspections necessary for power uprate related activities and provides guidance for use by the inspectors in conducting these inspections. As described above, the NRC staff has conducted an extensive review of the licensee's plans and analyses related to the proposed SPU and concluded that they are acceptable.

6.0 STATE CONSULTATION

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

7.0 ENVIRONMENTAL CONSIDERATIONS

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 April 30, 2008 (73 FR 23503). 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 June 23, 2008 (73 FR 35419). 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. U.S. Nuclear Regulatory Commission, "Review Standard for Extended Power Uprates," RS-001, December 2003 (ADAMS Accession No. ML033640024).

2. WCAP-16840-P, “Comanche Peak Nuclear Power Plant Stretch Power Uprate Licensing Report,” August 2007 (ADAMS Accession Nos. ML072490333 and ML072490336, Non-Publicly Available).

3. License Amendment Request (LAR) 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” and 3.7.17, “Spent Fuel Pool Assembly Storage” to Revised Rated Thermal Power from 3458 MWt to 3612 MWt, August 28, 2007 (ADAMS Accession No. ML072490131).

4. Supplemental Information to License Amendment Request (LAR) 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” and 3.7.17, “Spent Fuel Pool Assembly Storage” to Revised Rated Thermal Power from 3458 MWt to 3612 MWt, October 24, 2007 (ADAMS Accession No. ML073120098).

5. Clarification of Proprietary Nature of Information Regarding Gothic Code Input Data, November 7, 2007 (ADAMS Accession No. ML073230080).

6. Supporting Information Regarding the Proprietary Nature of Gothic Code Input Data, December 3, 2007 (ADAMS Accession No. ML073450847).

7. Supplement to License Amendment Request (LAR) 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” to Revised Rated Thermal Power from 3458 MWt to 3612 MWt, January 10, 2008 (ADAMS Accession No. ML080160117).

8. Supplement to License Amendment Request (LAR) 07-003, Response to Request for Additional Information Related to License Amendment Request Associated with Methodology Used to Establish Core Operating limits and LAR 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” to Revised Rated Thermal Power from 3458 MWt to 3612 MWt, January 29, 2008 (ADAMS Accession No. ML080390320).

9. Supplement to License Amendment Request (LAR) 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” to Revise Rated Thermal Power from 3458 MWt to 3612 MWt, January 31, 2008 (ADAMS Accession No. ML080390311).

10. Supplement to License Amendment Request (LAR) 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” to Revised Rated Thermal Power from 3458 MWt to 3612 MWt, February 21, 2008 (ADAMS Accession No. ML080590356).

11. Supplement to License Amendment Request (LAR) 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” to Revised Rated Thermal Power from 3458 MWt to 3612 MWt, February 26, 2008 (ADAMS Accession No. ML080650370).

12. Supplement to License Amendment Request (LAR) 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” to Revised Rated Thermal Power from 3458 MWt to 3612 MWt, February 28, 2008 (ADAMS Accession No. ML080660070).

13. Supplement to License Amendment Request (LAR) 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” to Revised Rated Thermal Power from 3458 MWt to 3612 MWt, March 6, 2008 (ADAMS Accession No. ML080710410).

14. Supplement to License Amendment Request (LAR) 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” to Revised Rated Thermal Power from 3458 MWt to 3612 MWt, April 17, 2008 (ADAMS Accession No. ML081150509).

15. Supplement to License Amendment Request (LAR) 07-004, Revision to the Operating License and Technical Specification 1.0, “Use and Application” to Revised Rated Thermal Power from 3458 MWt to 3612 MWt, May 14, 2008 (ADAMS Accession No. ML081420027).

16. RG 1.77, “Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized-Water Reactors,” May 1974 (ADAMS Accession No. ML003740279).

17. WCAP-16346, Revision 0, “Comanche Peak Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation,” October 2004.

18. Docket No. 50-244, Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 97, to Renewed Facility Operating License No. DPR-18, R. E. Ginna Nuclear Power Plant, Nuclear Regulatory Commission, July 11, 2006 (ADAMS Accession No. ML061380249).

19. WCAP-10325-P-A, (Proprietary) and WCAP-10326-A, (Non-proprietary), “Westinghouse LOCA Mass and Energy Release Model for Containment Design, March 1979 Version,” May 1983.

20. Letter from NRC to Westinghouse, “Acceptance of Clarifications of Topical Report WCAP-10325, “Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version (TAC No. MC7980),” October 18, 2005.

21. WCAP-8264, Rev. 1, August 1975 and WCAP-8312, Rev. 2, “Topical Report Westinghouse Mass and Energy Release Data Containment Design.”

22. WCAP-8822 (Proprietary), Mass and Energy Releases Following a Steam Line Rupture, September 1976; WCAP-8822-S1-P-A (Proprietary), Supplement 1 - Calculations of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture, September 1986; WCAP-8822-S2-P-A (Proprietary), Supplement 2 –Impact of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture for Dry and Subatmospheric Containment Designs, September 1986.

23. WCAP-14882-P-A, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

24. Letter from TXU Generation Company to NRC, "Comanche Peak Steam Electric Station (CPSES) Docket Nos. 50-445 and 50-446 License Amendment Request (LAR) 04-011 Revision to Technical Specification (TS 3.3.3) Post Accident Monitoring (PAM) Instrumentation and 3.6.8 Hydrogen Recombiners," dated October 28, 2004 (ADAMS Accession No. ML043070519).

25. Letter from NRC to TXU Generation Company, "Comanche Peak Steam Electric Station (CPSES), Units 1 and 2 - Issuance of Amendments [No. 117] Re: Elimination of Requirements for Hydrogen Recombiners And Hydrogen Monitors (TAC Nos. MC5147 and MC5148)" dated April 21, 2005 (ADAMS Accession No. ML051190780).

26. Letter from Luminant Power to NRC, "Comanche Peak Steam Electric Station (CPSES) Docket Nos. 50-445 and 50-446 Submittal of CSPES Units 1 and 2 Large and Small Break LOCA Analyses," dated July 31, 2007 (ADAMS Accession No. ML072200641).

27. Letter from NRC to Luminant Power, Comanche Peak Steam Electric Station, Units 1 and 2 - Issuance of Amendments 144 and 144 Re: Revision to Technical Specifications to Allow Use of Westinghouse-Developed/NRC-Approved Analytical Methods to Establish Core Operating Limits (TAC Nos. MD5243, MD5244, MD6212, and MD6213), April 2, 2008 (ADAMS Accession No. ML080500627).

28. Letter from NRC to Luminant Power, Comanche Peak, Units 1 & 2 - Issuance of Amendment Nos. 145 and 145 Re: Revise TSs 3.1.4, 3.4.10, and 3.7.1 to Reflect Cycle-Specific Safety Analysis Assumptions Re Adoption of Westinghouse Methodologies, April 3, 2008 (ADAMS Accession No. ML080580003).

29. U.S. Nuclear Regulatory Commission, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," NUREG-0800, Revision 3, March 2007 (ADAMS Accession No. ML070710376).

30. Westinghouse Electric Corporation, "Reference Core Report VANTAGE 5 Fuel Assembly," WCAP-10445-NP-A, September 1, 1985.

31. Westinghouse Electric Corporation, "VANTAGE+ Fuel Assembly Reference Core Report," WCAP-12610-P-A, April 1995 (ADAMS Accession No. ML020430250).

32. Westinghouse Electric Corporation, “Westinghouse Improved Performance Analysis and Design Model (PAD4.0),” WCAP-15063-P-A, July 2000 (ADAMS Accession No. ML003735304).

33. Westinghouse Electric Corporation, “Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel,” WCAP-13589-A, March 1995 (ADAMS Accession No. ML080630348).

34. Westinghouse Electric Corporation, “Westinghouse Reload Safety Evaluation Methodology,” WCAP-9273-P-A, July 1985.

35. American Nuclear Society, "Nuclear Safety Criteria for the Design of Pressurized Water Reactor Plants,” ANSI N18.2-1973, August 6, 1973.

36. Burnett, T. W. T., et al., Westinghouse Electric Corporation, “LOFTRAN Code Description,” WCAP-7907-P-A (Proprietary), WCAP-7907-A (Nonproprietary), April 1984 (ADAMS Accession No. ML080650325).

37. Letter from NRC to Luminant Power, Comanche Peak, Units 1 and 2, Issuance of Amendment Nos. 143 and 143, Re: Technical Requirements Surveillance 13.3.33.2 (TAC Nos. MD5639 and MD5640), February 29, 2008 (ADAMS Accession No. ML080220107).

38. Sung, Y. X., et al., Westinghouse Electric Corporation, “VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis,” WCAP-14565-P-A, October 1999.

39. Westinghouse Electric Corporation, “Revised Thermal Design Procedure,” WCAP-11397-P-A, April 1989 (ADAMS Accession No. ML080650330).

40. Technical Specifications for Comanche Peak Steam Electric Station, Units 1 and 2 (ADAMS Accession Nos. ML053180521 and ML053180525, respectively).

41. American Society of Mechanical Engineers, ASME Boiler and Pressure Vessel Code, Section III, “Nuclear Power Plant Components,” Article NB-7000, “Protection Against Overpressure.”

42. Westinghouse Electric Corporation, “ANC: A Westinghouse Advanced Nodal Computer Code,” WCAP-10965-P-A, September 1986 (ADAMS Accession No. ML080630392).

43. American Nuclear Society, “American National Standard for Decay Heat Power in Light Water Reactors,” ANSI/ANS-5.1-1979, August 1979.

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Attachment:
List of Acronyms

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Date: June 27, 2008

LIST OF ACRONYMS	
AC	alternating current
ADAMS	Agencywide Documents Access and Management System
AFW	auxiliary feedwater
AMP	aging management program
AMSAC	ATWS mitigation system actuation circuitry
ANC	American Nuclear Corporation
ANCO	Advanced Nodal Code
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOOs	anticipated operational occurrences
AOP	abnormal operating procedure
AOV	air-operated valve
ARAVS	auxiliary and radwaste area ventilation system
ART	adjusted reference temperature
ARV	atmospheric relief valve
ASME	American Society of Mechanical Engineers
ASME Code	ASME Boiler and Pressure Vessel Code
ASME OM Code	ASME Code for Operation and Maintenance of Nuclear Power Plants
ASTM	American Society of Testing and Materials
ATWS	anticipated transient without scram
BE-LBLOCA	best-estimate large-break loss-of-coolant accident
BL	bulletin
BLPB	branch line pipe break
BMI	bottom-mounted instrumentation
BOC	beginning of cycle
BOP	balance-of-plant
BRS	boron recovery system
BTP	branch technical position
BWR	boiling water reactor
CASS	cast austenitic stainless steel
CCW	component cooling water
cfm	cubic feet per minute
CFR	*Code of Federal Regulations*
CFS	condensate and feedwater system
CHF	critical heat flux
CHR	containment heat removal
COLR	core operating limits report
CPSES	Comanche Peak Steam Electric Station

LIST OF ACRONYMS	
CR	control room
CRAVS	control room area ventilation system
CRDM	control rod drive mechanism
CRDS	control rod drive system
CREA	control rod ejection accident
CS	containment spray
CSS	containment spray system
CST	condensate storage tank
CUF	cumulative usage factor
CVCS	chemical and volume control system
CWS	circulating water system
DBA	design-basis accident
DBLOCA	design-basis loss-of-coolant accident
DC	direct current
DE	dose equivalent
DEG	degree
DEHL	double-ended hot leg
DEI	dose equivalent iodine
DEPS	double-ended pump suction
DF	decontamination factor
DLM	diffusion layer model
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
EFPD	effective full-power day
EFPY	effective full-power year
EOC	end of cycle
EOL	end of license
EOP	emergency operating procedure
EPDM	ethylene propylene diene monomer
EPRI	Electric Power Research Institute
EQ	environmental qualification
ERCOT	Electric Reliability Council of Texas

LIST OF ACRONYMS	
ESF	engineered safety feature
ESFAS	engineered safety features actuation system
ESFVS	engineered safety feature ventilation system
FAC	flow-accelerated corrosion
FHA	fuel handling accident
FIV	flow-induced vibration
FLB	feedwater line break
FPP	fire protection program
fps	feet per second
FSAR	Final Safety Analysis Report
ft-lb	foot-pounds
FW	feedwater
GDC	general design criterion (or criteria)
GL	generic letter
GOTHIC	Generation of Thermal Hydraulic Information for Containments
gpd	gallon per day
gpm	gallon per minute
GSI	generic safety issue
GWD/MTU	gigawatt days per metric ton uranium
GWMS	gaseous waste management system
HELB	high-energy line break
HEPA	high-efficiency particulate air
HFP	hot full power
HZP	hot zero power
IASCC	irradiation-assisted stress-corrosion cracking
IFM	intermediate flow mixer
IGSCC	intergranular stress-corrosion cracking
IN	information notice
IP	inspection procedure
ISI	inservice inspection
IST	inservice testing
kV	kilovolt
kW/ft	kilowatt per foot
LAR	license amendment request
LBB	leak before break
lmb	mass flow rate

LIST OF ACRONYMS	
LCO	limiting condition for operation
LLHS	light load handling system
LOAC	loss-of-AC-power
LOCA	loss-of-coolant accident
LOL	loss of load
LOL/TT	loss of load/turbine trip
LONF	loss of normal feedwater flow
LOOP	loss of offsite power
LPZ	low-population zone
LRA	locked-rotor accident
LWMS	liquid water management system
mA	milliampere
MCES	main condenser evacuation system
MDAFP	motor-driven auxiliary feedwater pump
MDC	moderator density coefficient
MDLM	mist diffusion layer model
MEPC	moderate energy pipe crack
MeV	megaelectronvolts
MFIV	main feedwater isolation valves
MFP	main feed pump
MOV	motor-operated valve
MRP	materials reliability program
MS	main steam
MSIV	main steam isolation valve
MSLB	main steamline break
MSS	main steam system
MSSV	main steam safety valve
MTC	moderator temperature coefficient
MVA	megavolt amperes
MVAR	megavolt ampere reactive
MWD/MTU	megawatt days per metric ton uranium
MWe	megawatts electric
MWt	megawatts thermal
M&E	mass and energy
NEI	Nuclear Energy Institute
NPSH	net positive suction head

LIST OF ACRONYMS	
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NRS	narrow range span
NSSS	nuclear steam supply system
OM Code	Operations and Maintenance Code for Nuclear Power Plants
OT∆T	Overtemperature delta T
pcm	percent-millirho
PCWG	performance capability working group
PCT	peak cladding temperature
pH	potential of Hydrogen
PORV	power-operated relief valve
ppm	parts per million
PRT	pressurizer relief tank
PRV	pressure relief valve
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
P-T	pressure-temperature
PTLR	pressure-temperature limits report
PTS	pressurized thermal shock
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
RAI	request for additional information
RCCA	rod cluster control assembly
RCL	reactor coolant loop
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	regulatory guide
REA	rod ejection accident
rem	roentgen equivalent man
RHR	residual heat removal
RI	reactor internal
RIA	reactivity insertion accident
RPV	reactor pressure vessel
RTDP	revised thermal design procedure

LIST OF ACRONYMS	
RTNDT	reference temperature nil ductility transition
RTPTS	PTS [pressurized thermal shock] reference temperature
RTS	reactor trip system
RV	reactor vessel
RVHP	reactor vessel head penetration
RWAP	rod assembly withdrawal at power
RWST	refueling water storage tank
SAFDL	specified acceptable fuel design limit
SAL	safety analysis limit
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
SI	safety injection
Sm	design stress-intensity value
SPDS	safety parameter display system
SPU	stretch power uprate
SPULR	CPSES, Units 1 and 2 Stretch Power Uprate Licensing Report
SRP	Standard Review Plan
SS	stainless steel
SSCs	structures, systems, and components
SSE	safe-shutdown earthquake
SSER	supplemental safety evaluation report
SSI	safe shutdown impoundment
STDP	Standard Thermal Design Procedure
SWS	service water system
T_{avg}	average temperature
T_{cold}	cold-leg temperature
T_{hot}	hot-leg temperature

LIST OF ACRONYMS	
TAVS	turbine area ventilation system
TBS	turbine bypass system
TDAFP	turbine-driven auxiliary feedwater pump
TEDE	total effective dose equivalent
TG	turbine generator
TGSCC	transgranular stress-corrosion cracking
TGSS	turbine gland sealing system
TPCW	turbine plant cooling water
TRM	Technical Requirements Manual
TS	technical specifications
TSC	technical support center
UET	unfavorable exposure time
UHS	ultimate heat sink
USE	upper-shelf energy
VCT	volume control tank
µCi/gm	micro-curies per gram
ΔRTNDT	Change in reference temperature nil ductility transition