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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION RELATED TO AMENDMENT NO.163 TO FACILITY OPERATING LICENSE NO. NPF-16

FLORIDA POWER AND LIGHT COMPANY

ST. LUCIE PLANT, UNIT NO. 2

DOCKET NO. 50-389

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SAFETY EVALUATION FOR EXTENDED POWER UPRATE

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1.0 INTRODUCTION

1.1 Application

By application dated February 25, 2011, as supplemented by letters listed in Attachment 1, the Florida Power and Light Company (FPL or the licensee) requested changes to the Facility Operating License and Technical Specifications (TSs) for the St. Lucie Plant, Unit No. 2 (St. Lucie 2). The supplemental letters listed in Attachment 1 provided additional information that clarified the application and did not expand the scope of the initial application as originally noticed.

The proposed changes would increase the maximum steady-state reactor core power level from 2700 megawatts thermal (MWt) to 3020 MWt, which is an increase of approximately 11.85 percent. The proposed increase in power level is considered an extended power uprate (EPU).

The licensee's application dated February 25, 2011, also requested approval of the new fuel storage and spent fuel storage criticality analyses and amendments to TS 3.9.11, "Spent Fuel Storage Pool," and TS 5.6, "Fuel Storage," in support of fuel storage requirements. The licensee agreed with the NRC staff that the EPU and the fuel storage criticality analyses will be reviewed and processed separately. The license amendment and associated safety evalution (SE) for the fuel storage criticality analyses can be found at Agencywide Documents Access and Management System (ADAMS) Accession No. ML12243A415.

1.2 Background

St. Lucie 2 is a pressurized-water reactor (PWR) plant of the Combustion Engineering (CE) design with a containment structure comprised of a steel containment vessel surrounded by a reinforced concrete shield building. St. Lucie 2 is located along with St. Lucie 1 on Hutchinson Island in St. Lucie County about halfway between the cities of Fort Pierce and Stuart on the east cost of Florida. The condenser is cooled by the circulating water system which takes suction from and discharges to the Atlantic Ocean.

The U. S. Nuclear Regulatory Commission (NRC) originally licensed St. Lucie 2 on June 10, 1983, for operation at 2560 MWt. By Amendment No. 9 dated March 1, 1985, the NRC granted a power uprate to St. Lucie 2 of approximately 5 percent, allowing the plant to be operated at 2700 MWt. Therefore, the proposed EPU would result in an increase of approximately 18 percent over the original licensed power level and 11.85 percent over the current licensed power level for St. Lucie 2.

1.3 Licensee's Approach

The licensee's application for the proposed EPU follows the guidance in the Office of Nuclear Reactor Regulation's (NRR's) Review Standard (RS)-001, "Review Standard for Extended Power Uprates" (Reference 1), to the extent that the review standard is consistent with the design basis of the plant. Where differences exist between the plant-specific design basis and RS-001, the licensee described the differences and provided evaluations consistent with the design basis of the plant. Because the proposed EPU also include a measurement uncertainty recapture (MUR), the licensee also used Regulatory Issue Summary (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications."

The licensee will make the modifications necessary to implement the EPU during the refueling outage in fall 2012. Following NRC approval of the EPU and the completion of the refueling outage, the plant will be operated at 3020 MWt.

1.4 Plant Modifications

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

- Reactor and Reactor Protection System (RPS)
  - Implement EPU fuel design
  - Raise RPS steam generator (SG) low-level trip setpoint
  - Rescale pressurizer level control program
- Accident Mitigation Systems
  - Increase component cooling water (CCW) system heat removal margin
  - Maintain components' environmental qualification (EQ)
  - Modify CCW system pipe supports
- Spent Fuel Storage
  - Add METAMIC™ inserts to spent fuel pool (SFP) storage racks
- Steam and Power Conversion System
  - Replace moisture separator reheaters and upgrade related valves/controls
  - Increase steam bypass control system capacity and upgrade control system
  - Replace high and low pressure turbine steam paths
  - Replace main turbine electro-hydraulic control system
  - Upgrade steam and power conversion system instruments
  - Modify piping supports
- Condensate and Feedwater (FW) System
  - Upgrade main condenser
  - Replace condensate pumps
  - Replace main FW pumps and modify SG flow control valves

    - Replace heater drain pumps
    - Upgrade heater drain valves
    - Replace No. 5 FW heaters and upgrade level controls
    - Install leading edge flow meters
    - Upgrade FW controls and instrumentation
    - Modify piping supports
- Alternating Current (AC) Power Block
    - Replace main generator rotor and rewind stator
    - Replace main generator bushings, current transformers, and install power system stabilizer
    - Replace main generator hydrogen cool
    - Replace turbine cooling water heat exchangers (HXs)
    - Increase main generator hydrogen pressure
    - Replace main generator exciter coolers
    - Increase margin on AC electrical buses
    - Replace main transformers (MTs)
    - Upgrade iso-phase bus duct cooling system and supports
    - Modify switchyard components

The NRC staff's evaluation of the licensee's proposed plant modifications is provided in Section 2.0 of this 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) there is reasonable assurance that such 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 EPU on design-basis analyses. The NRC staff evaluated the licensee's application and supplements. The NRC staff also evaluated audits of certain information at the licensee's vendor site, and independent analyses, for areas where such analyses were deemed appropriate by the NRC staff.

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

Audits of analyses supporting the EPU were conducted in relation to the reactor systems review, including fuel design. The results of the audits are discussed in section 2.0 of this SE.

Independent NRC staff calculations were performed in relation to the following topics:

- Meteorological data
- Boron precipitation
- Internal cladding pressure
- Power-to-melt
- Peak cladding temperature

The results of the calculations are discussed in section 2.0 of this SE.

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material Surveillance Program

Regulatory Evaluation

The reactor vessel (RV) material surveillance program provides a means for determining and monitoring the fracture toughness of the RV beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the RV. Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix H provides the staff's requirements for the design and implementation of the RV material surveillance program. The NRC staff's review primarily focuses on the effects of the proposed EPU on the licensee's RV surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on (1) General Design Criterion (GDC) 14, which requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of 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 the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the RV beltline region; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria are contained in NUREG-0800, "Standard Review Plan" (SRP) Section 5.3.1.

Appendix H of 10 CFR Part 50 invokes, by reference, the guidance in American Society for Testing and Materials (ASTM) Standard Practice E185, "Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." ASTM Standard Practice E185 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 (ΔRT_{NDT}).

Technical Evaluation

Licensee Evaluation

RV Neutron Fluence

In the EPU Licensing Report (Reference 2), Section 2.1.1.2.2, the licensee discussed the RV neutron fluence projections for the EPU. The licensee indicated that although the EPU would normally result in an increase to the neutron fluence for the RV, there was actually a decrease in the 60-year projected neutron fluence because the EPU neutron fluence analysis used a more realistic approach that removed some of the conservatism from the pre-EPU 60-year neutron fluence analysis, while adding a 10 percent factor of conservatism to the EPU neutron fluence projections beginning with Cycle 23. The licensee stated that the EPU projected RV neutron fluence value at 55 effective full-power years (EFPY) of facility operation (corresponding to a 60 calendar year operating period) is compared to the pre-EPU 60-year neutron fluence value in Table 2.1.1-2 of (Reference 2) at the 0° azimuthal location. According to the licensee, the 0° location represents the peak neutron fluence for the RV plates, circumferential welds, and axial welds. In (Reference 2), Table 2.1.1-3, the licensee provided revised chemistry factor (CF) values for the RV surveillance materials, based on surveillance capsule neutron fluence values that were also updated for EPU conditions.

The licensee stated that the 60-year neutron fluence projection used in the EPU evaluation was calculated using a methodology consistent with Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." The licensee stated that, for EPU conditions, the peak 60-year neutron fluence projection was used for the RV upper shelf energy (USE), pressurized thermal shock (PTS) evaluation, and the calculation of the adjusted reference temperature (ART) for the development of the reactor coolant system (RCS) pressure-temperature (P-T) limits.

RV Materials Surveillance Program

The licensee provided a discussion of the impact of EPU on the RV materials surveillance program in Section 2.1.1.2 of the licensing report. In the LAR, the licensee provided a surveillance capsule withdrawal schedule that conservatively accounts for the 60-year EPU neutron fluence in Table 2.1.1-1 (Reference 2). The licensee stated that the effect of the changes in the neutron fluence projections due to EPU on the RV surveillance capsule withdrawal schedule was evaluated, and that both sets of neutron fluence values are judged sufficiently alike to warrant no change to the schedule in Table 2.1.1-1 (Reference 2). Therefore, the licensee concluded that the proposed EPU will have no impact on the surveillance capsule withdrawal schedule.

Staff Evaluation

RV Neutron Fluence

RG 1.190 describes acceptable ways to calculate RV neutron fluence. RG 1.190 states that neutron fluence calculations should adhere to an NRC-approved methodology and provide acceptable qualification criteria. The staff confirmed that the licensee used a neutron fluence methodology described in WCAP-16817-NP, "St. Lucie Unit 2 RCS Pressure and Temperature

Limits and Low Temperature Overpressure Protection Report for 55 Effective Full Power Years," Revision (Rev.) 2, October 2007 for determining the peak 60-year neutron fluence for EPU conditions. The staff confirmed that this neutron fluence methodology was previously approved by the staff for implementation at St. Lucie 2 as part of its evaluation for the current TS P-T limit curves (Reference 3). The staff confirmed that this methodology meets the requirements of RG 1.190, including consideration of dosimetry measurements from the tested surveillance capsules. Since the licensee used a methodology to project the RV neutron fluence that is consistent with the applicable regulatory guidance of RG 1.190 and has been approved by the NRC staff, the staff finds the end-of-license neutron fluence projections for St. Lucie 2 to be acceptable.

The staff confirmed that the peak neutron fluence, corresponding to the 0° azimuthal location for all RV beltline materials, was used as the neutron fluence input for the licensee's analyses of the impact of the EPU on the RV Charpy USE, P-T limits, and compliance with PTS requirements. The staff also verified that the licensee accurately addressed the impact of the EPU fluence value on the calculated CF values for the RV surveillance materials, based on the methods in Position 2.1 of RG 1.99, "Radiation Embrittlement of Reactor Vessel Materials," Rev. 2, May 1988, and the measured shifts in the reference nil-ductility transition temperature (ΔRT_{NDT}) values for the surveillance materials. Specifically, for the surveillance plate, which is representative of the limiting beltline material (Intermediate Shell Plate M-605-1) for the P-T limits and PTS analysis, the staff confirmed that the licensee accurately calculated the new CF value for EPU conditions, based on the updated capsule neutron fluence for 60 years.

RV Material Surveillance Program

ASTM E 185-82 recommends that, for a RV with a projected peak ΔRT_{NDT} at the RV inside surface of greater than 100 °F and less than or equal to 200 °F, the RV should have a minimum of four surveillance capsules scheduled for withdrawal and testing (including previously withdrawn capsules). The peak predicted transition temperature shift for St. Lucie 2, accounting for EPU conditions, is 128 °F for Intermediate Shell Plate M-605-1, at the inside surface of the RV. The St. Lucie 2 RV has six capsules, with four capsules in the withdrawal sequence (two of which have been previously withdrawn and tested) and two capsules designated as standby. Therefore, the staff determined that St. Lucie 2 satisfies this first ASTM E 185-82 criterion for EPU conditions. ASTM E 185-82 also recommends that, for a reactor with four surveillance capsules installed, the last capsule should be withdrawn at a capsule fluence greater than once but less than twice the peak end-of-license RV neutron fluence. As shown in Table 2.1.1-2 of the licensing report, the peak RV neutron fluence accounting for EPU conditions at 55 EFPY is 4.42×10^{19} n/cm^2 (E > 1.0 MeV). Per Table 2.1.1-1 of the licensing report, the fourth capsule is scheduled for withdrawal at approximately 44 EFPY, corresponding to a capsule neutron fluence of 4.5×10^{19} n/cm^2 (E > 1.0 MeV) for EPU conditions, which is greater than once but less than twice the peak RV neutron fluence at end-of-license. Therefore, since the projected neutron fluence for the fourth capsule is greater than once but less than twice the projected peak RV neutron fluence at end-of-license, the criterion of ASTM E 185-82 is met. The fifth and sixth capsules are designated standby and are not scheduled for withdrawal. The staff noted that the EPU will not affect the surveillance capsule withdrawal schedule for St. Lucie 2. Based on the above, the staff confirmed that the licensee accurately addressed the impact of the EPU on the RV surveillance capsule withdrawal schedule, as identified in the licensing report, Table 2.1.1-1.

Conclusion

Based on the above evaluation, the staff concludes that the method for calculating the end-of-license neutron fluence for the RV, which is used as the basis for the surveillance program, ART, USE, P-T limits, and PTS calculations, meets the applicable regulatory guidance of RG 1.190. Therefore, the staff finds that the licensee's neutron fluence methodology is acceptable for EPU conditions. The staff also concludes that the surveillance capsule withdrawal schedule for St. Lucie 2, accounting for EPU conditions, meets the ASTM E 185-82 criteria and thus meets the requirements of 10 CFR Part 50 Appendix H. Therefore, the staff finds that the St. Lucie 2 RV material surveillance program is acceptable for EPU conditions.

2.1.2 P-T Limits and Upper-Shelf Energy

Regulatory Evaluation

The NRC's acceptance criteria for P-T limits are based on:

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

Specific review criteria are contained in the SRP, Section 5.3.2.

Part 50 of 10 CFR, Appendix G, provides the staff's criteria for maintaining acceptable levels of USE for the RV beltline materials of operating reactors throughout the licensed lives of the facilities. The rule requires RV beltline materials to have a minimum USE value of 75 ft-lb in the unirradiated condition, and to maintain a minimum USE value above 50 ft-lb throughout the licensed period of operation 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 Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (B&PV Code). The rule also mandates that the methods used to calculate USE values must account for the effects of neutron irradiation on the USE values for the materials and must incorporate any relevant RV surveillance capsule data that are reported through implementation of a plant's 10 CFR Part 50, Appendix H RV material surveillance program.

Technical Evaluation

Upper Shelf Energy

Licensee Evaluation

In Section 2.1.2.2.1 of the licensing report, the licensee projected the USE values for 60 years using the peak neutron fluence value revised for the EPU. The licensee stated that the peak neutron fluence value at the one-quarter RV wall depth (1/4T) location was used for the EPU

USE calculations, and this value was calculated based on the RV inner surface neutron fluence value provided in Table 2.1.1-2 of the licensing report. The licensee further stated that the projected USE values were calculated in accordance with the methods specified in RG 1.99, Rev. 2. According to the licensee, the 60-year projected USE values demonstrate that the USE for all RV beltline materials will remain greater than 50 ft-lbs through the end of the 60-year operating period, thereby meeting the USE requirements of 10 CFR Part 50, Appendix G. The licensee's USE projections for 60 years are based on a 55 EFPY operating period, which is consistent with the EFPY operating period used for the projections of the nil-ductility reference temperature for PTS (RT_{PTS}).

Staff Evaluation

The staff reviewed Section 2.1.2.2 of the licensing report to determine (1) whether the applicant adequately addressed the impact of the EPU on the end-of-license (60 year, 55 EFPY) USE values for the RV beltline materials, and (2) whether the applicant demonstrated that the end-of-license USE values will remain in compliance with the USE requirements of 10 CFR Part 50, Appendix G, accounting for EPU conditions. Appendix G of 10 CFR Part 50 specifies that RV beltline materials shall maintain USE values no less than 50 ft-lbs during the operating life of the RV unless it is demonstrated that lower USE values would provide margins of safety against ductile fracture equivalent to those required by Appendix G of the ASME Code), Section XI. The staff's methods for calculating the projected percentage decrease in the USE, based on the material's copper content and projected neutron fluence, are specified in RG 1.99, Rev. 2.

The staff performed confirmatory calculations of the licensee's projected 60-year USE values using the EPU neutron fluence values at the 1/4T location provided in Table 2.1.2-1 of the licensing report and the methods specified in RG 1.99, Rev. 2, Position 1.2. The staff's calculations confirmed that the licensee accurately calculated the projected USE values for all RV beltine materials, and all beltline materials will maintain USE values greater than the 50 ft-lb minimum specified in 10 CFR Part 50, Appendix G for acceptance of end-of-license USE values without further analysis. Specifically, for the most limiting RV beltline material, Intermediate-to-Lower Shell Girth Weld 101-171, the staff independently confirmed that the 55 EFPY USE value is projected to be 71 ft-lbs, based on the methods in RG 1.99, Rev. 2, Position 1.2. Additionally, the staff confirmed that the unirradiated (initial) USE values and weight percentage copper content values, which were used as inputs for the 60-year USE projections, are consistent with those approved by the staff as part of its safety review for the renewed facility operating license.

Based on its review of the applicant's end-of-license USE analysis, accounting for EPU conditions, as documented above, the staff determined the applicant demonstrated that all RV beltline materials are projected to remain in compliance with the USE requirement specified in 10 CFR Part 50, Appendix G, accounting for EPU conditions through 60 years of facility operation.

P-T Operating Limits

Licensee Evaluation

In Section 2.1.2.2.3 of the licensing report, the licensee addressed the impact of the proposed EPU on the RCS P-T limit curves, which are established in the St. Lucie 2 TS. The licensee noted that if the EPU ART values exceed the values used for the current P-T limit curves, then the applicability date for the TS P-T limit curves must be established using the EPU projected neutron fluence and ART values. The licensee stated that the current (pre-EPU) P-T limit curves have been generated for operation to 60 years based on 55 EFPY neutron fluence projections and RG 1.99, Rev. 2, Position 1.1 CF values.

The licensee stated that the effect of the EPU on the applicability of the current TS P-T limit curves was evaluated by comparing the ART values for the current licensing basis (CLB) with the projected ART values after the EPU. For EPU conditions, the licensee proposed to use the existing TS P-T limit curves, with a revision to the EFPY operating period for which the curves are valid. The amended TS pages, provided in Attachment 3 to the licensee's EPU license amendment request (LAR), show the operating period for the P-T limits is revised from 55 EFPY to 47 EFPY. The licensee provided peak EPU fluence projections at 55 EFPY for the 1/4T and 3/4T locations in the RV beltline in Table 2.1.2-1 of the licensing report. The licensee provided CF values based on the methods in RG 1.99, Rev. 2, Positions 1.1 and 2.1 in Table 2.1.2-4 of the licensing report. The licensee stated that these CF values were used to compute ART values, and for those materials represented in the surveillance program with CF values based on Positions 1.1 and 2.1 from RG 1.99, Rev. 2, the higher of the two ART values was applied for determining the limiting ART value for EPU conditions.

Staff Evaluation

The staff reviewed Section 2.1.2.2 of the licensing report to determine (1) whether the applicant adequately addressed the impact of the EPU on the RCS P-T limit curves, which are established in the St. Lucie 2 TS, and (2) whether the applicant demonstrated that the proposed TS revisions for the P-T limit curves ensure that that curves will remain in compliance with the requirements of 10 CFR Part 50, Appendix G, accounting for EPU conditions.

The current TS P-T limit curves are valid through 55 EFPY. The LAR to incorporate these curves into the St. Lucie 2 TS was submitted to the NRC by letter dated January 23, 2008 (Reference 3). By letter dated January 29, 2009, the NRC issued License Amendment No. 154, wherein the staff approved these TS curves for RCS operation through 55 EFPY (Reference 4). Since the licensee did not generate new P-T limits for EPU, but instead revised the applicability period of the current approved P-T limits, the staff's review focused on the following:

- Determination of the limiting materials for the P-T limit curves for EPU conditions;
- Verification that the licensee correctly calculated the revised operating period for the EPU P-T limits.

With respect to the determination of the limiting materials, the staff's review took into consideration the impact of the EPU neutron fluence on the limiting RT_{NDT} for the RV, which must be adjusted to account for the effects of neutron embrittlement to determine an ART value, as required by 10 CFR Part 50, Appendix G. The methods for calculating the ART, based on a given neutron fluence, are provided in RG 1.99, Rev. 2. Appendix G of 10 CFR Part 50 specifies that the ART values for RV beltline materials must account for credible data resulting from the material surveillance program of 10 CFR Part 50, Appendix H. The staff's guidelines for surveillance data credibility assessments and the methods for applying credible surveillance data for determining RV beltline ART values are also specified in RG 1.99, Rev. 2. For the EPU, the limiting material (with respect to the ART values at the 1/4T and 3/4T locations) is represented in the licensee's surveillance program. Therefore, the staff's review of the new limiting ART values for EPU conditions addressed the impact of the revised surveillance material fluence values on the calculation of the limiting ART values.

Limiting Materials for Pre-EPU TS P-T Limit Curves

The staff determined that, other than the minimum temperature requirements, the current TS P-T limit curves (referred to as the "Pre-EPU" P-T limit curves), as approved per (Reference 4), were established based on the irradiated fracture toughness properties of the limiting beltline material at the 1/4T and 3/4T locations, which is a function of the ART value for the limiting material at these locations. The limiting RV beltline material with respect to ART at the 1/4T location is Intermediate Shell Plate M-605-2 (Heat No. B-3416-2), which had a calculated ART value of 160 °F based on a CF value of 91.5. The limiting RV beltline material with respect to ART at the 3/4T location is Intermediate Shell Plate M-605-1 (Heat No. A-8490-2), which has a calculated ART value of 137 °F based on a CF value of 74.2. Both the 1/4T and 3/4T limiting ARTs are based on Position 1.1 of RG 1.99, Rev. 2. The staff noted that Plate M-605-1 corresponds to the surveillance plate material, and a 3/4T ART value of 134 ºF was also calculated for Plate M-605-1, based on Position 2.1 methods from the RG (i.e., a linear fit to the credible surveillance data). However, for the limiting ART values for the current TS P-T limits, the licensee conservatively chose to use the higher ART of 137 °F determined using Position 1.1.

Limiting Materials for EPU TS P-T Limit Curves

The revised neutron fluence analysis included a recalculation of the neutron fluences of the previously withdrawn surveillance capsules, necessitating a recalculation of the CF of the surveillance plate material. The Position 2.1 methods resulted in a CF value for EPU conditions of 93.1 for Plate M-605-1, determined through a linear fit to the credible surveillance data. Using this CF and the 55-EFPY 1/4T and 3/4T neutron fluences resulted in ART values of 164 ºF at 1/4T and 138 ºF at 3/4T for Plate M-605-1(Heat No. A-8490-2). Therefore, for EPU conditions, Plate M-605-1 is the limiting material for both the 1/4T and 3/4T ART values. The revised Position 2.1 CF calculation for Plate M-605-1 for EPU conditions is shown in Table 2.1.1-3 of the licensing report. The staff confirmed that the licensee correctly calculated the EPU CF value for Plate M-605-1 (93.1) based on the methods of Position 2.1 of RG 1.99, Rev. 2.

Table 1 summarizes the 55 EFPY limiting ART values at the 1/4T and 3/4T locations, for both the pre-EPU (basis for current TS P-T limits) and EPU conditions.

Table 1 – Comparison of Limiting Materials and Adjusted Reference Temperatures for 55 EFPY, Pre-EPU and EPU Conditions

	Location	Limiting Material	ART (°F)	CF (°F)	RG 1.99, Rev. 2 Position
Pre-EPU	1/4T	Intermediate Shell Plate M-605-2	160	91.5	1.1 (tables)
EPU	1/4T	Intermediate Shell Plate M-605-1	164	93.1	2.1 (surveillance data)
Pre-EPU	3/4T	Intermediate Shell Plate M-605-1	137	74.2	1.1 (tables)
EPU	3/4T	Intermediate Shell Plate M-605-1	138	93.1	2.1 (surveillance data)

Recalculation of the Applicability Period of the TS P-T Limit Curves

For the TS P-T limit curves to remain valid under EPU conditions, the staff determined that the projected ART value for the EPU limiting plate, M-605-1, must remain less than or equal to 160 ºF at the 1/4T location. For the 3/4T location, the ART value for the EPU limiting plate, M-605-1, must remain less than or equal to 137 ºF. Based on the initial RT_{NDT} (30 ºF), margin term (17 ºF), and CF (93.1) value for EPU conditions, the staff determined that a 1/4T neutron fluence of 2.20 x 10^{19} n/cm^2 (E > 1.0 MeV) results in an ART of 160 ºF for this plate, and a 3/4T neutron fluence of 8.9 x 10^{18} n/cm^2 (E > 1.0 MeV) results in an ART of 137 ºF for this plate. The staff determined that if the 1/4T fluence value is less than or equal to 2.20 x 10^{19} n/cm^2 (E > 1.0 MeV), the 3/4T fluence is less than or equal to 7.99 x 10^{18} n/cm^2 (E > 1.0 MeV), based on the RG 1.99, Rev. 2 formula (Equation 3) for neutron fluence attenuation in the RV wall; thus 1/4T represents the bounding requirement for neutron fluence at 47 EFPY. Therefore if the peak 1/4T neutron fluence value at 47 EFPY is less than or equal to 2.20 x 10^{19} n/cm^2 (E > 1.0 MeV) the TS P-T limit curves are valid through 47 EFPY. The staff determined that the licensee must provide a peak neutron fluence value corresponding to 47 EFPY in order to confirm that the TS P-T limit curves will remain valid through 47 EFPY. Therefore, by letter dated December 6, 2011, the staff issued a request for additional information (RAI). Specifically, in RAI EVIB-1, the staff requested that the licensee provide a peak neutron fluence value corresponding to 47 EFPY.

By letter dated December 20, 2011 (Reference 5), the licensee provided its response to RAI EVIB-1. In its RAI response, the licensee stated that, for EPU conditions, the peak RV neutron fluence value corresponding to 47 EFPY is 3.67 x 10^{19} n/cm^2 (E > 1.0 MeV) at the inside diameter clad to base metal interface. The staff determined that a peak RV neutron fluence of 3.67 x 10^{19} n/cm^2 (E > 1.0 MeV) at the inside diameter clad to base metal interface corresponds to a peak 1/4T neutron fluence value of 2.19 x 10^{19} n/cm^2 (E > 1.0 MeV), based on the calculation of neutron fluence attenuation through the RV wall using Equation 3 from RG 1.99, Rev. 2.

The staff determined that the 1/4T and 3/4T ART values for the new limiting material, Plate M-605-1, will remain bounded by the 1/4T and 3/4T limiting ART values for the current TS P-T limit curves until the peak neutron fluence at the 1/4T location reaches a value of 2.20 x 10^{19} n/cm^2 (E > 1.0 MeV). Based on its review of the applicant's response to RAI

EVIB-1, the staff determined that the peak 1/4T neutron will remain less than 2.20 x 10^{19} n/cm^2 (E > 1.0 MeV) through 47 EFPY for EPU conditions. Therefore, the staff determined that the licensee's proposal to use the existing TS P-T limit curves for EPU conditions, with the curves EFPY applicability period revised from 55 EFPY to 47 EFPY, as shown in the amended TS pages, is acceptable.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the USE values for the RV beltline materials at end-of-license and on the TS P-T limit curves. The staff finds that the licensee has adequately addressed the changes in neutron fluence and its impact on the end-of-license USE values. The staff concludes that the St. Lucie 2 RV will continue to remain in compliance with the USE requirements specified in 10 CFR Part 50, Appendix G, through the expiration of the current operating license. With respect to the TS P-T limit curves, the staff finds that the licensee's proposal to use the existing TS P-T limit curves for EPU conditions, with the curves EFPY applicability period revised from 55 EFPY to 47 EFPY, as shown in the amended TS pages, is acceptable. Therefore, the staff concludes that the TS P-T limit curves will remain in compliance with the requirements of 10 CFR Part 50, Appendix G through 47 EFPY.

2.1.3 Pressurized Thermal Shock

Regulatory Evaluation

The PTS evaluation provides a means for assessing the susceptibility of the RV beltline materials to PTS events to assure that adequate fracture toughness is provided to support reactor operation. The 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 PTS methodology and the calculation of the reference temperature, RT_{PTS}, at the expiration of the license, considering neutron embrittlement effects. The NRC's acceptance criteria for PTS are based on (1) GDC 14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture; (2) GDC 31, which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; 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.

The staff has established requirements in 10 CFR 50.61 that are designed to protect the RVs of PWRs against the consequences of PTS events. The rule requires licensees owning PWR-designed light-water reactors to calculate a nil-ductility reference temperature at end-of-license neutron fluence (RT_{PTS} as defined in 10 CFR 50.61) for each base metal and weld material in the RV made from carbon or low-alloy steel materials. The rule also requires the RT_{PTS} values to be maintained below the PTS screening criteria throughout the serviceable life of the facilities. The rule sets a maximum limit of 270 °F for RT_{PTS} 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 RT_{PTS} values that are calculated for circumferential weld materials.

Section 50.61 of 10 CFR provides a required methodology for calculating these RT_{PTS} values, which are based on the calculation methods in RG 1.99, Rev. 2. For materials in the beltline region of the RV, the rule requires that the calculations account for the effects of neutron irradiation on 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 material surveillance program.

Technical Evaluation

Licensee Evaluation

In Section 2.1.3.2 of the licensing report, the licensee discussed its evaluation of the impact of the EPU on the 60-year projected RT_{PTS} values for the RV beltline materials. The licensee stated that the peak neutron fluence value at the RV clad/base metal interface was used to calculate the 60-year RT_{PTS} values for EPU conditions. Table 2.1.3-1 of the licensing report lists the 60-year (55 EFPY) peak neutron fluence value for pre-EPU and EPU conditions. Consistent with its discussion of neutron fluence values in Sections 2.1.1.2 and 2.1.2.2 of the licensing report, the licensee noted that there was a slight decrease in projected 60-year peak neutron fluence for the EPU because the EPU fluence analysis used more recent core power histories that superseded the more conservative fluence projections from prior the 60-year neutron fluence analysis, while adding a 10 percent factor of conservatism to the fluence projections beginning with Cycle 23.

For the EPU, the licensee stated that 60-year projected RT_{PTS} values were calculated using the methods specified in 10 CFR 50.61. With respect to the irradiation temperature, the licensee stated that the EPU results in a slight increase in the irradiation temperature from 549 ºF to 551 ºF. The licensee addressed this effect by stating that the irradiation temperature remains within the range of applicability for the methods identified in RG 1.99, Rev. 2, which correspond to the calculation methods specified in 10 CFR 50.61. The licensee stated that the overall effect of the irradiation temperature increase is small but beneficial because higher temperatures decrease the rate of irradiation embrittlement. For RV beltline materials not represented in the surveillance program, the licensee stated that the 60-year RT_{PTS} values for the EPU are based on CF values that were calculated in accordance with Table 1 and 2 of 10 CFR 50.61, which are identical to the table used to determine CFs in accordance with Position 1.1 of RG 1.99, Rev. 2. The licensee stated that Intermediate Shell Plate M-605-1 corresponds to the surveillance plate. Therefore the CF value was calculated using Equation 5 from 10 CFR 50.61, which corresponds to the methods in Position 2.1 of RG 1.99, Rev. 2. The measured ΔRT_{NDT} data, reduced fluence values, and detailed CF calculation for the surveillance plate are presented in Table 2.1.3-3 of the licensing report. The licensee's CF values for all RV beltline materials are presented in Table 2.1.3-4 of the licensing report. The licensee stated that the limiting RV beltline material for PTS is Intermediate Shell Plate M-605-1, which corresponds to the surveillance plate. The licensee's calculation determined that, accounting for EPU conditions, the 60-year RT_{PTS} value for this plate is 175 ºF. The licensee also determined that, accounting for EPU conditions, the 60-year projected RT_{PTS} values for all RV beltline materials are less than the screening criteria specified in 10 CFR 50.61. Accordingly, the licensee concluded that it has adequately addressed the impact of the EPU on PTS, and therefore the proposed EPU is acceptable with respect to PTS.

Staff Evaluation

The staff reviewed Section 2.1.3.2 of the licensing report to determine (1) whether the applicant adequately addressed the impact of the EPU on the projected 60 year RT_{PTS} values for the RV beltline materials, and (2) whether the applicant demonstrated that the 60 year RT_{PTS} values will remain in compliance with the PTS requirements of 10 CFR 50.61, accounting for EPU conditions. The requirements of 10 CFR 50.61 specify that all RV beltline materials shall have projected values for RT_{PTS} that are acceptable to the NRC. RT_{PTS} values that are projected to remain less than the screening criteria specified in 10 CFR 50.61(b)(2) are acceptable for the duration of the facility operating license. The methods for calculating RT_{PTS} values are specified in 10 CFR 50.61(c), which are similar to the recommended methods specified in RG 1.99, Rev. 2.

The staff performed confirmatory calculations of the licensee's projected 60-year (55 EFPY) RT_{PTS} values using the EPU neutron fluence values at the RV clad/base metal interface provided in Table 2.1.3-1 of the licensing report and the methods specified in 10 CFR 50.61(c). The staff's calculations confirmed that the licensee accurately calculated the RT_{PTS} for all RV beltine materials, accounting for EPU conditions. The staff's calculations also confirmed that the projected RT_{PTS} values for all RV beltline materials are less than the applicable screening criteria specified in 10 CFR 50.61(b)(2). Specifically, for the most limiting RV beltline material, Intermediate Shell Plate M-605-1, the staff independently confirmed that the 55 EFPY RT_{PTS} value is projected to be 175 ºF, based on the methods in 10 CFR 50.61(c), and this value is less than the screening limit of 270 ºF specified in 10 CFR 50.1(b)(2). Additionally, the staff confirmed that the unirradiated (initial) RT_{NDT} values, weight percentage copper and nickel content values, and margin terms, which were used as inputs for the 60-year RT_{PTS} projections, are consistent with those approved by the staff as part of its safety review for the renewed facility operating license. The staff verified that, consistent with the requirements of 10 CFR 50.61(c), the CFs used to calculate RT_{PTS} values were determined using identical methods to those that were used to calculate the CF's for determining the ART used for the TS P-T limit curves, accounting for EPU. The staff also noted that the RT_{PTS} value for the limiting material, M-605-1, was calculated using a CF value (93.1) based on credible surveillance data, as specified in 10 CFR 50.61(c)(2). As discussed above in Section 2.1.2, the staff determined that this CF value was correctly determined based on the surveillance data for M-605-1.

Based on its review of the licensee's projected 60-year RT_{PTS} values, accounting for EPU conditions, as documented above, the staff determined the applicant demonstrated that all RV beltline materials are projected to remain in compliance with the PTS requirements specified in 10 CFR 50.61, accounting for EPU conditions, through 60 years of facility operation (55 EFPY).

Conclusion

The staff has reviewed the licensee's projected end-of-license RT_{PTS} values, accounting for EPU conditions. Based on its confirmatory RT_{PTS} calculations, the staff concludes that all RV beltline materials will meet the applicable PTS screening criteria specified in 10 CFR 50.61 through the end-of-license (55 EFPY). Therefore, the staff concludes that the PTS analysis for St. Lucie 2, accounting for EPU conditions, is acceptable.

2.1.4 Reactor Internal and Core Support Materials

Regulatory Evaluation

The RV internals (RVI) 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's review assessed the impact of the EPU on the margins of safety for maintaining the structural integrity of the RVI components. The NRC's acceptance criteria for RVI materials are based on GDC 1 and 10 CFR 50.55a for inspecting and evaluating the structural integrity of RVI components. Section 50.55a of 10 CFR specifies the ASME Code editions and addenda that are approved for use by the NRC. The ASME Code, Section II contains the allowable materials. Specific review criteria are contained in SRP Section 4.5.2 and other review criteria and guidance are provided in Matrix 1 of NRC Review Standard, RS-001, Rev. 0. For PWRs, Matrix 1 of RS-001, Rev. 0, "Review Standard for Extended Power Uprates," provides references to the NRC's approval of the recommended guidelines for RVI components in Topical Report WCAP-14577, Rev. 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals (March 2001)." The staff also observes that under "Other Guidance," Matrix 1 of RS-001 refers to Note 1, which states, in part, that "[f]or thermal and neutron embrittlement of cast austenitic stainless steel, stress-corrosion cracking, and void swelling, licensees will need to provide plant-specific degradation management programs or participate in industry programs to investigate degradation effects and determine appropriate management programs."

Technical Evaluation

Licensee Evaluation

In Section 2.1.4.1 of the licensing report, the licensee included their regulatory evaluation and a discussion of the CLB of St. Lucie 2 with respect to RVI components. The licensee stated that WCAP-14577 does not apply in its entirety to CE-designed RVI components, and therefore only the applicable criteria are applied to St. Lucie 2.

In their discussion of the CLB, the licensee noted that the St. Lucie 2 design bases conform with the NRC GDC for Nuclear Power Plants specified in 10 CFR Part 50, Appendix A, as discussed in Final Safety Analysis Report (FSAR) Section 3.1. The licensee also indicated that the materials of construction for the RVI components are documented in FSAR Section 4.5.2.1. The licensee stated that discussions of the applicable codes, standards, records, and quality assurance (QA) program criteria for the all safety-related SSCs, including the RVI components are provided in the FPL Quality Assurance Topical Report FPL-1.

In its discussion of the current license basis, the licensee also noted that the RVI components were evaluated for the St. Lucie 2 license renewal application (LRA). The applicant indicated that Section 2.3.1.4 of the SER for license renewal (NUREG-1779 (Reference 6)) identifies that RVI components are within the scope of license renewal, and that programs used to manage the aging effects associated with the RVI and core support components are discussed in the license renewal SER, Sections 3.1.0.7 and 3.1.4, and Chapter 18 of the updated FSAR.

In Section 2.1.4.2 of the licensing report, the licensee described the materials of construction of the RVI components as primarily Type 304 stainless steel, with limited use of high-strength precipitation hardening austenitic stainless steel and solution-annealed Type 316 stainless steel in some fastener applications. The applicant indicated that there are a limited number of fasteners because welded construction was used wherever possible. Other materials include Stellite hardfacing (cobalt-based alloy) at potential wear points such as the snubber spacer blocks on the core support barrel outside surface and Type 403 stainless steel for the upper internals hold down ring. The licensee stated in this section that there are no applications of nickel-based Alloy 600 or weld metals Alloys 82 or 182 in the RVI components and that there are no applications of high-strength, precipitation-hardening nickel-base Alloys in the RVI components.

Section 2.1.4.2 of the licensing report states that the primary objective of the RVI materials assessment was to ensure that the EPU conditions (primary coolant chemical conditions, temperature and neutron fluence) will not result in any new aging effects for the RVI materials through the end of the 60-year operating period nor change the manner in which component aging will be managed by the aging management programs (AMPs).

The licensee listed the following relevant degradation (aging) mechanisms for the RVI components that were evaluated to assess the effects of the EPU:

A. Integrity of RV Fuel Cladding
B. Intergranular and Transgranular Stress Corrosion Cracking (IGSCC and TGSCC) of Austenitic Stainless Steel
C. Irradiation-Enhanced Embrittlement
D. Irradiation-Assisted Stress Corrosion Cracking (IASCC) of Austenitic Stainless Steel
E. Irradiation-Induced Void Swelling of Austenitic Stainless Steel
F. Thermal Aging (Embrittlement) of Cast Austenitic Stainless Steel (CASS)
G. Irradiation-Enhanced Stress Relaxation of Threaded Structural Fasteners (TSFs).

In Section 2.1.4.2.2 of the licensing report, the licensee described the service conditions for the RVI components that will result from EPU. According to the licensee, the RCS chemistry conditions are maintained by the RCS chemistry program, and these conditions are bounded by the water chemistry conditions that were analyzed for the EPU, with respect to boron concentration, lithium concentration, elevated temperature pH, and impurities. The core outlet temperature will increase from 598 °F to 607.9 °F and the core inlet temperature will increase from 548.6 °F to 551 °F. With respect to internal temperature of the RVI components, the licensee indicated that the maximum value of the long-term steady-state temperature in the RVI components as the result of gamma heating is 735.8 °F, which will be at a subsurface location in the former plates of the core shroud near the mid-section of the core. The licensee stated that the maximum neutron fluence after 60 years (55 EFPY) at the inner surface of the core shroud, accounting for EPU conditions, is 7.01×10^{22} n/cm^2 (E > 1MeV) and stated that the areas of maximum neutron fluence are at the core shroud inner surfaces opposite the center regions of the reactor core.

In Section 2.1.4.2.3 of the licensing report, the licensee evaluated the changes expected due to the EPU for each aging mechanism listed above. The licensee identified no significant changes to the severity of the aging mechanisms due to the EPU. For both IGSCC and TGSCC, the licensee concluded no significant changes would occur in these mechanisms because the temperature increases are minor and because the reactor coolant chemistry will not change.

With respect to irradiation embrittlement, the licensee identified the core shroud as the limiting component and listed several other components that are potentially affected by this mechanism. The licensee indicated that the increase in neutron fluence due to EPU would not cause significant additional decreases in fracture toughness for these RVI components.

With respect to IASCC, the licensee listed RVI components that are potentially susceptible. The licensee concluded that operating experience did not indicate IASCC will become a major problem for PWR RVI components, either with or without EPU, but could not be completely ruled out. The licensee provided a threshold neutron fluence of 1×10^{21} n/cm^2 (E > 1.0 MeV) for IASCC. The licensee listed the RVI components that are potentially susceptible to IASCC based on this threshold. The licensee indicated that additional industry data is needed to assess this mechanism, and until that data is available, IASCC will be managed through ISIs conducted in accordance with Section XI of the ASME Code, Subsections IWB, IWC, and IWD and the RVI Inspection Program. The licensee additionally credited the Chemistry Control Program for management of IASCC of RVI components.

The licensee concluded that the total amount and severity of void swelling in the RVI components will be minor at the end of the 60-year license period and will be managed through ISIs conducted in accordance with Section XI of the ASME Code, Subsections IWB, IWC, and IWD Program and the RVI Inspection Program. The licensee also listed the Chemistry Control program as a program that manages void swelling of RVI components.

With respect to thermal aging embrittlement of CASS components, the licensee stated that the only components fabricated from CASS are the control element assembly (CEA) shroud tubes and the flow bypass inserts. According to the licensee, the temperature of these components for EPU conditions is determined by the core outlet temperature of 607.9 °F. The licensee stated that both components use CASS with molybdenum content < 0.5 percent, which is less susceptible than high molybdenum content components. The licensee stated that the CEA shroud tubes were fabricated from centrifugal castings and are therefore, not susceptible to thermal aging regardless of delta ferrite content. The licensee stated that the flow bypass inserts fabrication specifications permitted either static or centrifugal castings, and the delta ferrite content for these components is not known. Accordingly, the licensee determined that these components are potentially susceptible to thermal aging.

The licensee stated that the CASS components may also be exposed to significant neutron radiation. Accordingly, the licensee identified the synergistic effects of neutron embrittlement and thermal embrittlement as a potential concern CASS components with neutron fluence exposure greater than 10^{17} n/cm^2 (E > 1.0 MeV) and that are also susceptible to thermal embrittlement. The licensee identified the flow bypass inserts as susceptible to the synergistic effects of neutron embrittlement and thermal embrittlement because they experience neutron fluence in excess of the 10^{17} n/cm^2 (E > 1.0 MeV) threshold and are assumed to be susceptible to thermal embrittlement based on the assumed static casting method and unknown delta ferrite content. The licensee stated that the embrittlement of the CASS flow bypass inserts will be managed by the RVI inspection Program and the Thermal Aging Embrittlement of CASS Program.

The licensee's evaluation of irradiation-enhanced stress relaxation of RVI components concluded that the small increases in neutron fluence and temperature due to EPU would not adversely affect stress relaxation of RVI components. The licensee stated that several TSFs are considered susceptible to stress relaxation. The licensee stated that the effects of aging (i.e., loss of preload) on these TSFs due to irradiation-enhanced stress relaxation will be managed by the inservice inspection (ISI) Program for the ASME Code, Section XI, Subsections IWB, IWC, and IWD.

The licensee concluded that there are no new degradation mechanisms for the RVI components resulting from the EPU. The licensee also concluded that the AMPs identified to manage the effects of aging due to these mechanisms are appropriate, and no changes are needed to these AMPs. With respect to the aging management review of the RVI components conducted for license renewal, the licensee concluded that there are no changes to the materials, component or system functions, system boundaries, and AMPs identified. The licensee also concluded the RVI components will continue to meet the regulatory requirements for GDC 1 and 10 CFR 50.55a after implementation of the EPU.

Staff Evaluation

Matrix 1 of Review Standard RS-001 provides the NRC staff's basis for evaluating the potential for EPUs to affect the aging mechanisms identified above. In RS-001, Matrix-1, the staff states that, in addition to the SRP, guidance on the neutron irradiation-related threshold level for IASCC in RVI components is given in WCAP-14577, Rev. 1-A. The staff also noted that for the RVI aging mechanisms identified by the licensee, Electrical Power Research Institute (EPRI) Topical Report 1012081, "Materials Reliability Program [MRP]: PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values (MRP-175)," December 2005 recommends specific screening criteria based on neutron fluence threshold levels.

The staff compared the licensee's evaluation of the aging mechanisms for the RVI components for the EPU to the licensee's evaluation of the aging effects and mechanisms for license renewal. The staff noted that in the LRA for St. Lucie, Units 1 and 2, the aging mechanisms identified for the RVI components are consistent with those identified for the EPU. The staff noted that the LRA identified the loss of material due to wear as an aging effect. While this aging effect is not specifically addressed in the licensing report, the staff determined that the loss of material due to wear would be caused by loss of preload in bolted connections and changing flow patterns in the core region. As discussed below, the licensee did address the effects of irradiation-enhanced stress relaxation on the loss of preload in TSFs for EPU conditions, and the licensee's evaluation determined that the EPU will not increase flow rates in the core region sufficiently to impact the rate of wear.

In the licensing report, the effects of the EPU are evaluated for the following aging mechanisms for the RVI components: fuel cladding corrosion, SCC, irradiation embrittlement, IASCC, void swelling, thermal embrittlement, and irradiation-enhanced stress relaxation.

The susceptibility of the St. Lucie 2 RVI components to these aging mechanisms (with the exception of fuel cladding corrosion) was assessed for license renewal as documented in the St. Lucie, Units 1 and 2 LRA and the associated SER (Reference 6). The LRA indentified the following aging effects and the mechanisms that cause the aging effect: 1) cracking due to SCC and IASCC, 2) reduction in fracture toughness due to irradiation embrittlement and thermal embrittlement, 3) loss of material due to wear, 4) loss of mechanical closure integrity due to cracking (SCC and IASCC) and stress relaxation, 5) loss of preload due to stress relaxation, and 6) dimensional change due to void swelling. No additional components were identified in the licensing report as susceptible to these effects due to EPU, compared to those components previously identified as susceptible to these effects.

Neutron fluence and temperature are important parameters with respect to assessing the susceptibility of RVI components to these aging mechanisms. In particular, threshold neutron fluence levels are identified for certain aging mechanisms in industry guidance documents and topical reports such as WCAP-14577, Rev. 1-A and MRP-175. WCAP-14577, Rev. 1-A establishes a neutron fluence threshold of 1×10^{21} n/cm^2 (E > 1.0 MeV) for the initiation of IASCC, loss of fracture toughness, and/or void swelling in PWR RVI components made from stainless steel (including CASS) or Alloy 600/82/182 materials. MRP-175 provides recommended screening criteria for each of the above aging mechanisms based on more detailed threshold fluence values. In identifying components as potentially susceptible to these aging mechanisms the staff found that the licensee generally applied the most conservative (i.e., lowest fluence threshold) screening criteria for identifying susceptible components for EPU conditions. Section 2.1.4.2.2 of the licensing report provides the post-EPU values of the end-of-license neutron fluence, the core inlet and outlet temperatures, and the peak metal temperature due to gamma heating.

For the EPU, the changes in RCS operating conditions that could potentially affect aging mechanisms associated with the RVI components are neutron fluence and RCS temperature within the core region. The staff determined that the applicant correctly identified all of the aging mechanisms that are potentially affected by changes in these operating conditions as a result of the EPU.

With respect to adequacy of the licensee's existing AMPs to manage the aging of the RVI, the licensee credits its RVI Inspection Program for managing cracking due to SCC and IASCC, loss of fracture toughness due to irradiation embrittlement and thermal aging, change in dimensions due to void swelling, and loss of preload due to stress relaxation. With respect to the RVI Inspection Program, the staff observes that FPL committed in the LRA to "submit a report summarizing the aging effects applicable to reactor vessel internals, including a description of the inspection plan," prior to the end of the current 40-year operating term for St. Lucie 2 (see NUREG-1779 (Reference 6) Section 3.1.0.7 and FSAR Supplement Section 18.1.4 (Appendix A of the LRA)). FPL also committed to perform a one-time inspection of the RVI components (to implement the enhanced inspections of the RVI Inspection Program). NUREG-1779 (Reference 6) also documents that St. Lucie, Units 1 and 2 are participating in the EPRI MRP effort related to RVI, which would provide additional bases for inspections under the RVI program. The licensee did not specifically commit during the license renewal process to implement an RVI inspection program consistent with the guidance of the standard industry program as did most of the later license renewal applicants.

Based on its July 8, 2011, response to an RAI that was issued for the staff's review of the EPU for St. Lucie 1, the licensee committed to implementing the NRC-approved version of the PWR RVI inspection and evaluation (I&E) guidelines provided in EPRI Topical Report 1016596, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-Rev. 0)," as modified by the staff's final SE for MRP-227, for managing the effects of aging on the St. Lucie 1 RVI components. Similar to the RAI response for

St. Lucie 1, the staff determined that the licensee should submit a statement for addressing its commitment to implement the NRC-approved version of the MRP-227 guidelines at St. Lucie 2. Therefore, in RAI EVIB-2 the staff requested that the licensee submit a statement addressing its intent to revise the current FSAR Section 18.1.4 commitments to require implementation of the NRC-approved version of the MRP-227 guidelines for St. Lucie 2 (MPR-227-A, (Reference 7)). By letter dated December 20, 2011 (Reference 5), the licensee provided its response to RAI EVIB-2. In its RAI response, the licensee stated that FPL hereby revises its current commitments associated with the aging management of the St. Lucie 2 RVI components during the period of extended operation to adopt the NRC-approved version of the MRP-227 guidelines (i.e., MRP-227-A) in place of the existing RVI Inspection Program. The licensee's RAI response includes a revision to the current commitments associated with aging management of the RVI components to require implementation of the MRP-227-A guidelines during the period of extended operation. The staff found the licensee's RAI response acceptable because the licensee confirmed that its current commitments related to aging management of the RVI components at St. Lucie 2 are revised to require implementation of MRP-227-A guidelines during the period of extended operation, in place of the existing RVI inspection program.

The staff's evaluation of the effects of the EPU on the specific applicable aging mechanisms is addressed below, with the exception of fuel cladding corrosion effects, which is discussed in Section 2.8.

Stress Corrosion Cracking (SCC)

The staff determined that the licensee adequately addressed the effects of the EPU on IGSCC and TGSCC for the RVI components. The staff notes that IGSCC and TGSCC are not specifically affected by increases in neutron fluence resulting from the EPU; the effects of neutron irradiation on SCC are addressed as a separate aging mechanism – IASCC, which is discussed below. However, the staff determined that the applicant correctly addressed the small temperature changes in the core region as a potential contributor to IGSCC and TGSCC. Furthermore, the staff agreed that the small increases in the core inlet and outlet temperatures would not result in a significant increase in the susceptibility of the RVI components to IGSCC and TGSCC, because the RCS Chemistry Program ensures that aggressive ions are maintained below the levels required to initiate IGSCC and TGSCC. The staff also agreed that the EPU will not result in the introduction of any aggressive chemical species that could affect the susceptibility of the RVI components to IGSCC and TGSCC. Specifically, the concentrations of dissolved oxygen and halogens are unaffected by the EPU, and RCS pH operating conditions are bounded by those analyzed for the EPU. The staff determined that the licensee's RCS Chemistry Program will continue to provide adequate mitigation of aging effects related to IGSCC and TGSCC. With respect to IGSCC susceptibility of Alloy A-286 TSFs, the staff agreed that the susceptibility of A-286 TSFs will likely not be affected by the EPU, because peak stresses will remain below the 100 kilopound-force per square inch threshold identified as a result of the analyses of previous failures of A-286 TSFs. In addition, since Topical Report MRP-227-A specifies methods acceptable to the staff for managing cracking due to SCC (including IGSCC and TGSCC) of RVI, the staff finds that IGSCC of A-286 TSFs will be adequately managed in accordance with the RVI Inspection Program.

Irradiation Embrittlement

The staff noted that, based on the neutron fluence data reported in Section 2.1.4.2.2 of the licensing report and Table 2.1.4-2, the most limiting RVI component for EPU conditions, with respect to loss of fracture toughness due to irradiation embrittlement, will continue to be the inner surface of the core shroud, which is comprised of stainless steel plates and welds. Based on the data reported in MRP-175, Section F.4, the staff determined that, for wrought stainless steel components and stainless steel weld metals exposed to neutron fluence levels greater than 40 displacements per atom (dpa) prior to the implementation of the EPU, any additional increase in neutron fluence as a result of the EPU would result in no significant additional decrease in fracture toughness due to the plateau of stainless steel material properties as a function of neutron fluence in dpa. Therefore, the staff agreed with the licensee's statement in Section 2.1.4.2.3 of the licensing report, that the additional fluence resulting from EPU conditions will not cause significant additional decrease in fracture toughness for the core shroud plates and welds, because, as reported in Section 2.1.4.2.2 of the licensing report , the maximum projected 60-year fluence at the inner surface of the shroud is 7.01 x 10^{22} n/cm^2 (E > 1.0 MeV), approximately equivalent to 102 dpa, for EPU conditions.

In Section 2.1.4.2.3 of the licensing report, the licensee identified all other stainless steel RVI components (wrought and CASS components) that are expected to be exposed to sufficient neutron fluence for EPU conditions to undergo significant decreases in fracture toughness due to irradiation embrittlement. The staff determined that the licensee correctly identified these components using neutron fluence screening criteria that are more conservative than the threshold fluence values for irradiation embrittlement identified in MRP-175.

The staff determined that the licensee adequately identified the programs necessary for managing the effects of aging (i.e., loss of fracture toughness) due to neutron irradiation embrittlement for these RVI components: The ISI Program, which conducts inspections in accordance with the requirements of the ASME Code, Section XI, Subsections IWB, IWC, and IWD; and the RVI Inspection Program. In addition, since Topical Report MRP-227-A specifies methods acceptable to the staff for managing loss of fracture toughness due to neutron irradiation embrittlement of RVI, the staff finds that these programs are adequate for addressing loss of fracture toughness due to irradiation embrittlement.

Irradiation-Assisted Stress Corrosion Cracking

In Section 2.1.4.2.3 of the licensing report, the licensee identified the stainless steel RVI components (wrought and CASS components, including welds) that are projected to be exposed to sufficient neutron fluence for EPU conditions to be considered potentially susceptible to IASCC. The staff determined that the licensee correctly identified these components using a neutron fluence screening criterion of 1 x 10^{21} n/cm2 (E > 1.0 MeV), which is more conservative / bounding than the corresponding threshold fluence value for IASCC identified in MRP-175 (2 x 10^{21} n/cm2 (E > 1.0 MeV)).

The staff determined that the licensee adequately identified the programs necessary for managing the effects of aging due to IASCC for these RVI components: The Inservice Inspection (ISI) Program, which conducts inspections in accordance with the requirements of the ASME Code, Section XI, Subsections IWB, IWC, and IWD; the RCS Chemistry Program; and the RVI Inspection Program. In addition, since Topical Report MRP-227-A specifies methods acceptable to the staff for managing cracking due to IASCC of RVI, the staff finds that, these programs are adequate for managing cracking due to IASCC of RVI components.

Void Swelling

MRP-175 identifies neutron fluence and temperature-based screening criteria for accessing whether RVI components may be susceptible to significant distortions and/or loss of fracture toughness from void swelling. Consistent with these screening criteria, the licensee identified the regions of the core shroud behind the reentrant corners, which are closest to the reactor core, and at the center of the core region where the horizontal plate is thicker, as being susceptible to significant void swelling. The licensee stated that the susceptible regions are localized and limited in number, and therefore the total amount of void swelling in the core shroud should not be significant at the end of 60 years accounting for EPU conditions. The staff agreed that void swelling has not yet been a significant issue in PWRs. However the staff determined that the potential core shroud aging effects associated with void swelling should be managed during the 60-year operating period.

The staff determined that the licensee adequately identified the programs necessary for managing the potential effects of aging due to void swelling in the core shroud: The Inservice Inspection (ISI) Program, which conducts inspections in accordance with the requirements of the ASME Code, Section XI, Subsections IWB, IWC, and IWD; and the RVI Inspection Program. In addition, since Topical Report MRP-227-A specifies methods acceptable to the staff for managing aging effects caused by void swelling of RVI, the staff finds that these programs are adequate for managing change in dimensions and loss of fracture toughness due to void swelling.

Thermal Aging

The NRC staff has identified thermal aging (i.e., embrittlement) of CASS RVI components as a contributor to the susceptibility of these components to non-ductile fracture due to the reduction in fracture toughness caused by this aging mechanism. Additionally, the synergistic effects of thermal embrittlement and neutron irradiation embrittlement may result in significant decreases in fracture toughness for susceptible components. NUREG-1801, Volume 2, "Generic Aging Lessons Learned (GALL) Report," Rev. 1, September 2005 (GALL Rev. 1), Chapter XI, Section XI.M13 (GALL Section XI.M13) specifies that CASS components susceptible to thermal aging be identified based on (1) casting method (i.e. static cast components vs. centrifugal cast components), (2) molybdenum content, and (3) delta ferrite content. Static castings, high molybdenum, and high delta ferrite contents result in a CASS component that is more susceptible to thermal embrittlement. For potentially susceptible components (identified based on the three screening criteria above), the GALL program provides for the consideration of the synergistic loss of fracture toughness due to neutron embrittlement and thermal aging embrittlement. For each such component, an applicant/licensee can implement either (a) a supplemental examination of the affected component as part of a 10-year ISI program during the license renewal term, or (b) a component-specific evaluation to determine the component's susceptibility to loss of fracture toughness.

The staff determined that the licensee identified the CASS RVI components at St. Lucie 2: the CEA shroud tubes and the flow bypass inserts. The temperature of both sets of components is determined by the EPU core outlet temperature (607.9 ºF) based on negligible gamma heating. According to the licensee, both applications use CASS with low molybdenum content (less than

0.5 percent). The staff noted that low molybdenum content CASS components are less susceptible to thermal embrittlement than high molybdenum content components. Furthermore, given that the CEA shroud tubes were fabricated from centrifugal castings, the staff agreed with the licensee's assertion that the CEA shroud tubes would not be susceptible to thermal embrittlement regardless of delta ferrite content, based on the CASS thermal embrittlement screening criteria identified in the GALL Program. Based on the licensee's statement that the casting method for the flow bypass inserts permitted either static or centrifugal castings, and these components have unknown delta ferrite content, the staff agreed that the flow bypass inserts were appropriately identified by the licensee as susceptible to thermal embrittlement.

For the flow bypass inserts, the staff agreed the licensee adequately addressed the impact of the small core outlet temperature change due to the EPU on the potential for the CASS flow bypass inserts to incur a reduction in fracture toughness in a shorter period of time. However, the staff agreed with the licensee's statement that the lower bound fracture toughness for these components will not be affected by the small temperature increase. Additionally, the staff found that the licensee adequately addressed the potential for the flow bypass inserts to undergo a reduction in fracture toughness due to the synergistic effects of thermal embrittlement and irradiation embrittlement. GALL Section XI.M13 indicates that the reduction in fracture toughness due to the synergistic effect may occur at fluence levels greater than 1×10^{17} n/cm^2 (E > 1.0 MeV). Since the flow bypass inserts are identified as susceptible to thermal aging and are exposed to neutron fluence greater than the above threshold, the staff determined that the licensee correctly identified these components as requiring aging management under the RVI Inspection Program and the Thermal Aging Embrittlement of CASS Program. These AMPs are described in FSAR Chapter 18. In addition, since Topical Report MRP-227-A specifies methods acceptable to the staff for managing loss of fracture toughness due to thermal aging, the staff finds that these programs are adequate for managing loss of fracture toughness due to thermal aging of RVI components.

Irradiation-Enhanced Stress Relaxation

MRP-175 identifies both irradiation-enhanced stress relaxation and thermal stress relaxation as potential contributors to the loss of preload for TSFs. While the literature data are limited regarding definitive stress relaxation threshold criteria and the extent of stress relaxation due to irradiation and thermal effects, the MRP-175 report does recommend a conservative screening criterion for irradiation-enhanced stress relaxation: 1.3×10^{20} n/cm^2 (E > 1.0 MeV), corresponding to approximately 0.2 dpa. Accordingly, it is recommended that all bolted PWR internals locations that reach or exceed this threshold be further evaluated for functionality during the operating life of the plant.

The staff determined that the licensee applied the above irradiation-enhanced stress relaxation screening criterion for identifying the RVI components susceptible to irradiation-enhanced stress relaxation during the 60-year operating period: the A-286 CEA shroud bolts and upper internals guide lug insert bolts. The licensee noted that, although these bolts are not located adjacent to the reactor core, these bolts are within the scope of aging management to detect evidence of loss of bolt preload, based on projected bolt fluence exceeding the MRP-175 screening criterion for stress relaxation identified above. With respect to thermal stress relaxation, the staff determined that this could become a contributor to the overall loss of preload for the CEA shroud bolts and the guide lug insert bolts; however the effects of the small temperature changes due to the EPU on the overall loss of preload would be negligible. The staff determined that the licensee's existing ISI Program may not be adequate for managing the potential aging effects, specifically loss of bolt preload and loss of material due to wear, associated with both thermal and irradiation-enhanced stress relaxation. However, the staff determined that the temperature and fluence changes associated with the EPU will not have a significant impact on the loss of preload due to stress relaxation for the subject TSFs. In addition, since Topical Report MRP-227-A specifies methods acceptable to the staff for managing loss of preload due to stress relaxation of RVI, in RAI EVIB-2, the staff requested the licensee to discuss whether it would implement the MRP-227-A guidelines for the management of stress relaxation. In its December 20, 2011, response to RAI EVIB-2, the licensee stated that MRP-227-A includes inspection requirements for RVI components that are subject to stress relaxation, and the FPL commitments associated with aging management of the St. Lucie 2 RVI components are revised to require implementation of the MRP-227-A guidelines. Accordingly, the staff finds that loss of preload due to stress relaxation will be adequately managed by the RVI Inspection Program.

Summary

Based on its review as discussed above, the staff determined that the licensee adequately addressed the impact of the proposed EPU on the aging mechanisms discussed above, with respect to changes in neutron fluence and temperature within the core region. The staff determined that the licensee adequately identified the RVI components susceptible to aging degradation due to the mechanisms discussed above, based on the previously established fluence thresholds identified for these aging mechanisms in WCAP-14577, Rev. 1-A and MRP-175. The staff also noted that the licensee has committed to implementing the MRP-227-A guidelines for aging management of its RVI components at St. Lucie 2.

The staff notes that when the plant-specific RVI component inspection program conforming to MRP-227-A is submitted to the staff for review, the staff will review the program to ensure that it includes an evaluation confirming that the operating conditions for St. Lucie 2, are bounded by the operating conditions (neutron fluence, temperature, etc.) assumed as the basis for the development of the generic I&E guidelines for RVI components in MRP-227-A, as required by Applicant/Licensee Action Item No. 1 from Section 4.2 of the staff final SE for MRP-227-A.

RIS-001, in Note 1 to Matrix 1, states that for thermal and neutron embrittlement of CASS, SCC, and void swelling, licensees will need to provide plant-specific degradation management programs or participate in industry programs to investigate degradation effects and determine appropriate management programs. As noted above, the licensee has an existing commitment to implement a plant-specific AMP for the RVI components. In addition, the program will be consistent with NRC-approved Topical Report MRP-227-A, which takes into account the industry findings on void swelling, SCC, and thermal and neutron embrittlement of CASS, and which the staff determined contains acceptable methods for managing thermal and neutron embrittlement of CASS, SCC, and void swelling of RVI components. Therefore, the staff finds that the recommendation in Note 1 of Matrix 1 of RIS-001 is met.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RVI components to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in operating temperature and neutron fluence on the integrity of these components.

The staff finds that the licensee has appropriately evaluated the potential for age related degradation of the RVI components because it considered the changes in neutron fluence, temperature, and water chemistry in its evaluation. The staff agrees with the licensee's conclusion that the RVI components will experience no new aging mechanisms or effects due to the EPU and that the previously identified aging mechanisms and effects (identified through the aging management review process conducted for license renewal) will continue to be adequately managed by the programs identified (RVI Inspection Program, ASME Section XI IWB, IWC, and IWD Program, and the Water Chemistry Program) for EPU conditions. Furthermore, the staff determined that the licensee has committed to implementing the MRP-227-A guidelines for aging management of its RVI components at St. Lucie 2, and the MRP-227-A guidelines provide acceptable I&E criteria for managing all known aging effects associated with the RVI components.

Consistent with Matrix 1 of RS-001, the staff further concludes that the licensee has committed to an augmented inspection program for the RVI and core support components to ensure that the components will continue to meet the requirements of GDC 1 and 10 CFR 50.55a following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to maintaining the structural integrity of the RVI components.

2.1.5 Reactor Coolant Pressure Boundary Materials

Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff's review of 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 nonbrittle 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 primary water stress-corrosion cracking (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.

The staff notes that the design bases of St. Lucie 2 conforms with the NRC GDC as specified in 10 CFR Part 50, Appendix A, effective May 21, 1971, and subsequently amended July 7, 1971, and February 12, 1976. St. Lucie 2 fully satisfies and is in compliance with the GDC as discussed in FSAR Section 3.1.

Technical Evaluation

The licensee's evaluation of RCPB materials covered the design specification, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. The staff notes that the licensee did not change any of the materials of construction in the RCPB as a result of this power uprate. As a result, the licensee applied less emphasis on the issues of design specifications and fabrication and processing and more emphasis on the issues of compatibility with the reactor coolant, susceptibility to degradation, and degradation management programs. The staff concurs with this approach because the issues of design specification and fabrication and processing are primarily issues associated with new materials or components and the remaining issues related to material degradation associated with changes in the RCPB environment. In its application, the licensee stated that the principle materials from which the RCPB is constructed include: a) carbon and low alloy steel; b) austenitic stainless steel; c) Alloy 600/82/182; and, d) Alloy 690/52/152. In its application the licensee also stated that the primary environmental changes within the RCPB as a result of the EPU will include: a) an increase in RCS hot leg temperature of 5.9 °F and RCS cold leg temperature of 2.35 °F; and b) potential changes in water chemistry including lithium, boron and pH, but not zinc, hydrogen, dissolved oxygen, chlorides, sulfates or other contaminants. The pH values of the RCS water will remain between 7.15 and 7.2. The staff notes that the principal modes of potential material degradation in the RCS system are: a) loss of material due to various forms of corrosion including corrosion due to boric acid; b) transgranular cracking; c) PWSCC; and, d) thermal aging. While the potential exists that the severity of the previously mentioned degradation mechanisms may increase, no additional degradation mechanisms are foreseen.

The paragraphs that follow will consider the effect of the projected environmental changes on each combination of material and degradation effect.

Carbon and Low Alloy Steel - Loss of Material

In its application the licensee stated that due to the replacement of the nine Alloy 600 instrument and sampling nozzles in the hot leg by the half nozzle repair process, a small amount of carbon steel hot leg piping is permanently exposed to reactor coolant. The staff notes that some corrosion of carbon steel components can be expected in hot, dilute boric acid solutions such as occur in the reactor coolant. The staff also notes that WCAP-15973-P-A, Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Program, addresses this corrosion issue. The staff further notes that the licensee utilized this reference at the time the repairs were made to determine that sufficient corrosion allowances prior to meeting minimum ASME Code criteria were available. The staff finally notes that the EPU environmental conditions are bounded by those used in WCAP-15973-P-A. This indicates to the staff that the original analysis remains valid under the EPU conditions.

In its application the licensee also addressed the concept of leakage of reactor coolant onto the external surfaces of RCS components. The staff notes that while the corrosivity of the leaking fluid is very low, rapid evaporation of water causes the formation of solid boric acid in conjunction with a highly concentrated boric acid solution on the external surfaces of RCS components. This concentrated solution of boric acid corrodes carbon steel at an appreciable rate. The staff also notes that the rate of corrosion of steel exposed to concentrated boric acid is primarily a function of the solution concentration and to a lesser extent on the absolute temperature of the solution. The staff finds that the change in chemistry of the reactor coolant will have no effect on corrosion of the external surfaces of RCS components since the concentration of boric acid in the reactor coolant is essentially unrelated to the concentration following evaporation on the external surface of the components. The staff also finds that the change in corrosion rate on the external surfaces of steel components due to the EPU temperature rise will be insignificant due to the small change in temperature (1060 degrees Rankine (^{o}R) to 1066 ^{o}R which is a change of 1.0 percent). The licensee stated that it manages potential corrosion on the external surfaces of carbon and low alloy steel components due to reactor coolant leakage through the use of AMP XI.M10, Boric Acid Corrosion, as contained in Rev. 1 of the GALL Report (NUREG 1801). The staff identified this approach to corrosion management as being acceptable for the current operating conditions while evaluating the licensee's application for license renewal. The staff finds that the Boric Acid Corrosion AMP will remain an effective tool to mitigate corrosion of the external surfaces of carbon and low alloy steel components under the EPU conditions.

Carbon and Low Alloy Steel - Transgranular Cracking, PWSCC, Thermal Aging

The degradation mechanisms, transgranular cracking, PWSCC, and thermal aging are not likely to occur under environmental conditions resembling either the current operating conditions or those for the EPU for carbon or low alloy steels. Additionally, based on material characteristics such as chemical composition, crystal structure, and active/passive behavior, the staff finds no basis to expect these degradation mechanisms in carbon or low alloy steels exposed to either the current or EPU operating conditions. The staff, therefore, finds that these degradation mechanisms have insignificant impact on RCPB materials under the EPU conditions.

Austenitic Stainless Steel - Loss of Material

In its discussion of carbon and low alloy steel components, the licensee states that the internal surfaces of most carbon and low alloy steel components are clad with austenitic stainless steel. The licensee also states that the EPRI PWR Water Chemistry Guidelines indicates that increasing initial lithium concentrations up to 3.5 parts per million (ppm) with controlled boron concentrations to maintain pH values between 6.9 and 7.4 does not produce undesirable material integrity issues. The staff concurs with the licensee's interpretation of the EPRI guidelines. The staff also notes that due to its passive condition, stainless steel is highly resistant to corrosion in near neutral pH solutions, as maintained by the proposed lithium and boric acid additions to the coolant. The staff, therefore, finds that the loss of material due to corrosion of stainless steel by reactor coolant is not a significant concern at either the existing or the proposed EPU environmental conditions.

Austenitic Stainless Steel - Transgranular Cracking

In its discussion of stress corrosion cracking of austenitic stainless steels, the licensee identifies transgranular cracking as a possible degradation mechanism for austenitic stainless steels. The licensee also states that transgranular cracking of austenitic stainless steels occurs only in the presence of halogens such as chlorides and dissolved oxygen. The licensee further states that its current water chemistry is within EPRI recommended guidelines and that, relative to halogens and oxygen, the water chemistry will not change under EPU conditions. The staff notes that one of the objectives of the EPRI water chemistry guidelines is the prevention of transgranular cracking. The licensee finally states that, in the absence of an increase in chlorides or oxygen, the slight increase in temperature under the EPU conditions will not result in the occurrence of transgranular cracking of stainless steel. Based on its knowledge of the extensive body of literature associated with transgranular cracking of stainless steels, the staff finds that: a) the licensee has correctly identified the conditions that may lead to transgranular cracking; and, b) the licensee has correctly concluded that transgranular cracking is not expected under current operating conditions. Based on the absence of changes in critical contaminants (i.e., chlorides and oxygen) between current and EPU conditions, the staff also concurs with the licensee's assessment that transgranular cracking of stainless steel is not expected under EPU conditions. The staff, therefore, finds that additional precautions on the part of the licensee for the prevention of transgranular cracking under EPU conditions are not required.

Austenitic Stainless Steel - PWSCC

PWSCC does not generally occur in stainless steels; however, some instances of intergranular cracking have occurred in sensitized stainless steel under dead leg conditions (see NRC IN 2006-27). While these instances technically meet the definition of PWSCC (i.e., intergranular cracking of material exposed to primary water) they are generally called IGSCC and are thought to be caused by issues such as crevices, high halogens, and/or high oxygen concentrations. Given the absence of operating experience of PWSCC in stainless steels exposed to reactor coolant meeting the EPRI water chemistry guidelines, the staff finds that, in the absence of additional contaminants, the slight increase in temperature expected at EPU conditions would not likely lead to PWSCC in stainless steel materials.

Austenitic Stainless Steel - Thermal Aging

The staff notes that some CASSs are subject to thermal aging. Thermal aging manifests itself as an increase in hardness and yield strength and a decrease in ductility and toughness. The staff also notes that the degree of aging is a function of the chemistry of the steel and the process by which it was cast. The rate of degradation is a function of the operating temperature of the material. The licensee indicated that CASS is present in both the hot leg and cold leg piping.

In its discussion of thermal aging of CASS, the licensee indicated that it has evaluated its CASS components against the standards established in NUREG-1801 (GALL Report AMP XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS). Based on that evaluation the licensee stated that some, but not all of its CASS material met the AMP criteria for exclusion from aging management. Excluded components include the reactor coolant pump (RCP) casings, pump covers, and valve bodies. The licensee also stated that the aging of the remaining material was being managed through the use of the AMP. The licensee further stated that the increase in temperature between the current and EPU conditions would not cause an increase in the number of components for which aging management was required. The licensee finally stated that while the components subject to aging management may reach their minimum toughness values more quickly due to the slight increase in temperature under the EPU operating conditions, the AMP does not require any modification to the program as a result. The staff finds that the licensee has accurately assessed the pertinent technical aspects of thermal aging of austenitic stainless steel (i.e., an increase in temperature will affect the rate but not the extent of toughness reductions for a CASS component).

The staff also finds that the licensee has correctly interpreted the information regarding the management of aging of CASS components contained within the AMP. The staff, therefore, finds that no further action is required on the part of the licensee relative to thermal aging of CASS as a result of the EPU temperature change. The staff also notes that the water chemistry change associated with the EPU will not affect thermal aging of CASS because thermal aging of CASS is a thermal rather than chemically driven process.

Alloy 600/82/182 - PWSCC

In its application the licensee acknowledges that the primary mode of degradation of Alloy 600/82/182 components is PWSCC. To mitigate this mode of degradation, the licensee has replaced most of the Alloy 600/82/182 components and welds in the RCPB. Despite this replacement program, some Alloy 600/82/182 components/welds remain. The following components in the RCPB still contain Alloys 600/82/182:

- Five hot-leg pipe weld pads used for the half-nozzle repairs of Alloy 600 instrument nozzles;
- Nozzle-to-safe-end DM welds of the following cold leg nozzles: letdown and drain, safety injection, charging inlet, spray, and RCP suction and discharge nozzles;
- Twelve cold-leg instrument nozzles and the welds connecting the nozzles to the RCS piping and connecting the nozzles to austenitic stainless steel safe-ends;
- Thirty pressurizer heater sleeves and the Alloy 182 in the partial penetration welds between the sleeves and pressurizer bottom head. The licensee states that the EPU will not result in an increase in the pressurizer operating temperature or in changes in the chemical conditions of the primary coolant in the pressurizer; thus, the potential for PWSCC of these parts and welds will not be affected by the EPU; and
- One pressurizer Alloy 690 replacement instrument nozzle has an Alloy 82 weld pad on the pressurizer outside diameter (OD) surface.

These components/welds are subject to PWSCC under current operating conditions, and, because time for PWSCC crack initiation is reduced as temperature is increased, they are subject to a more rapid onset of PWSCC under EPU conditions. The licensee has calculated that the time required for initiation of PWSCC cracks will decrease approximately 21 percent in hot leg locations as a result of the 5.9 ^{o}F temperature increase anticipated as a result of the EPU.

The only hot leg location that has not been replaced or mitigated is the drain nozzle safe-end weld. The staff notes that a much smaller decrease in time to PWSCC initiation will occur for cold leg locations (approximately 10 percent compared to the pre-EPU temperature). The licensee proposes to address the issue of PWSCC through the use of its Alloy 600 management plan. The licensee stated that this plan follows industry experience, identifies and ranks Alloy 600/82/182 locations, develops and maintains inspection plans and develops mitigation/repair replacement strategies for remaining Alloy 600/82/182 components.

The staff finds that the licensee's approach to managing PWSCC in the remaining hot-leg location is acceptable because the licensee has been and will continue to inspect this weld during each refueling outage and plans to replace or mitigate the weld at a future outage. This inspection frequency is in accordance with ASME code case N-770-1 for both current and EPU hot leg temperatures. Code case N-770-1 with conditions has been incorporated by reference into 10 CFR 50.55a.

The staff finds that the licensee's approach to managing PWSCC in the cold leg locations containing Alloy 600/82/182 is acceptable because: a) the licensee has a comprehensive Alloy 600 management plan; b) the plan has been effective in managing hot leg components under current operating conditions; c) the cold leg conditions under power uprate conditions are cooler than the hot leg conditions under current operating conditions indicating that the program has been demonstrated to be sufficiently robust to address cracking under the cold leg EPU conditions; d) the Alloy 600 management plan was examined as part of the license renewal process and found to be acceptable; and, e) the licensee needs to inspect Alloy 600/82/182 material in accordance with ASME Code Case N-770-1 with conditions as required in 10 CFR 50.55a(g)(6)(ii)(F).

To minimize PWSCC, the licensee must perform inspections of Alloy 600.82/192 material in accordance with ASME Code Case N-722, N-729-1 and N-7701 in 10 CFR 50.55a. The staff finds that PWSCC in Alloy 600/82/182 under the EPU conditions will be managed appropriately through inspections as required by 10 CFR 50.55a.

Alloy 600/82/182 - Thermal Aging

In its application, the licensee fails to address thermal aging of Alloy 600/82/182. The staff notes, however, that thermal aging of Alloy 600/82/182 has not yet been observed by the staff under environmental conditions resembling either the current operating conditions or those for the EPU. The staff also notes that thermal aging has been observed only in cast austenitic stainless steels. Thermal aging in these steels is a function of casting method, molybdenum content and delta ferrite content. The staff further notes that cast Alloy 600/82/182 is not used in nuclear power plants. The staff additionally notes that the nickel and chromium equivalents in Alloys 600/82/182 are such that no delta ferrite is expected. The staff finally notes that Alloy 600 contains no more than trace level of molybdenum. The staff, therefore, finds that thermal aging of Alloy 600/82/182 is not a significant degradation mechanism under the EPU conditions.

Alloy 690/52/152 - Loss of Material

In its application the licensee does not specifically address the susceptibility to loss of material of Alloy 690/52/152 components or welds. The staff notes that based on the chemical composition of these materials, high nickel and chromium contents which lead to passive behavior, these materials, when exposed to reactor coolant, are expected to be highly resistant to corrosion. The staff further notes an absence of operating experience indicating that these alloys are susceptible to loss of material. An examination of Rev. 2 to the GALL Report reveals that there are no entries for loss of material due to any form of corrosion for nickel alloys exposed to reactor coolant. The GALL Report does contain entries for loss of material due to mechanisms such as wear or fretting for nickel alloy components exposed to reactor coolant. As part of its license renewal process, the licensee has AMPs for the affected components which are designed to detect and manage loss of material. The staff notes that while increases in flow velocity which are likely to be associated with EPU conditions may accelerate this type of wear, the AMPs in use by the licensee are not specific to any given flow rate and therefore will monitor loss of material in Alloy 690/52/152. Due to the presence of these programs and to the fact that they are not specific to the existing plant conditions, the staff finds that the licensee's approach for addressing loss of material of Alloy 690/52/152 components and welds under EPU conditions is acceptable.

Alloy 690/52/152 - Transgranular Cracking

In its application, the licensee fails to address transgranular cracking of Alloy 690/52/152 (i.e., cracking of austenitic materials due to the presence of oxygen and halides). The staff notes, however, those materials with high nickel contents such as Alloys 690/52/152 are less susceptible to this form of degradation than Alloy 600/82/182. The staff finds that transgranular cracking will not significantly affect Alloy 690/52/152 under the EPU conditions.

Alloy 690/52/152 - PWSCC

In its application the licensee states that, based on substantial laboratory data, Alloy 690/52/152 is significantly more resistant to PWSCC than Alloy 600/82/182. The licensee also states that, based on 20 years of field experience for Alloy 690 and 15 years of field experience for Alloy 52/152, there have been no reports of PWSCC up to temperatures of 653 ^{o}F. The staff has incorporated the use of ASME code case N-729-1 and N-770-1 in 10 CFR 50.55a. These code cases address examination requirements for PWR RV upper heads and examination requirements for class 1 PWR piping and vessel nozzle welds fabricated from Alloy 82/182 with or without mitigation activities (including weld overlays with Alloy 52/152). The staff finds that compliance with these code cases as incorporated in 10 CFR 50.55a is sufficient to address concerns of PWSCC in Alloy 690/52/152 piping components and welds. (The staff's evaluation of Alloy 690 SG tubing is discussed in the SG section of this SE.) The staff finds that PWSCC in Alloy 690/52/152 under the EPU conditions will be monitored and addressed by the above ASME Code Cases as incorporated by reference in 10 CFR 50.55a.

Alloy 690/52/152 / Thermal Aging

In its application, the licensee does not address thermal aging of Alloy 690/52/152. The staff notes, however, that thermal aging of Alloy 690/52/152 has never been observed by the staff under environmental conditions resembling either the current operating conditions or those for the EPU. The staff also notes that thermal aging has been observed only in cast austenitic stainless steels. Thermal aging in cast austenitic stainless steels is a function of casting method, molybdenum content and delta ferrite content. The staff further notes that cast Alloy 690/52/152 is not used in nuclear power plants. The staff additionally notes that the nickel and chromium equivalents in Alloys 690/52/152 are such that no delta ferrite is expected. The staff finally notes that Alloy 690 contains no more than trace levels of molybdenum. The staff, therefore, finds that thermal aging of Alloy 690/52/152 is not a significant degradation mechanism under the EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of RCPB materials. The NRC staff further concludes that the licensee has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of GDC 1, GDC 4, GDC 14, GDC 31, 10 CFR Part 50, Appendix G, and

10 CFR 50.55a. Therefore, the NRC staff finds the proposed EPU acceptable with respect to RCPB materials.

2.1.6 Leak-Before-Break

Regulatory Evaluation

Leak before break (LBB) analyses provide a means for eliminating from the design basis the dynamic effects of postulated pipe ruptures. 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 overpressurizations, 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 SRP Section 3.6.3 and other guidance provided in Matrix 1 of RS-001.

The design bases of St. Lucie 2 conforms to the NRC GDC as specified in 10 CFR Part 50, Appendix A, effective May 21, 1971, and subsequently amended July 7, 1971, and February 12, 1976.

Technical Evaluation

In section 2.1.6.2 of its application, the licensee states that the current structural design basis for the plant includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. The licensee also stated that the original LBB analysis was conducted in accordance with CE Owner's Group (CEOG) Report CEN-367-A Rev. 000, Leak Before Break Evaluation of Primary Coolant Loop Piping in Combustion Engineering Designed Nuclear Steam Supply Systems [NSSSs], February 1991. As denoted by the "-A" in the report designation, the approach for the analysis of LBB, which is described in the report, has been accepted by the staff. The staff's SE is included in the report. The licensee further stated that, as part of its license renewal it requested Westinghouse Electric Company (Westinghouse) to conduct a plant specific reevaluation of the original LBB analysis for the EPU conditions.

The results of the review determined that the only changes in the input parameters affecting LBB were the normal operating loads on the primary loop piping, which were different from the original analysis. However, the EPU piping loads are bounded by the piping loads previously evaluated.

Staff guidance for LBB analyses is contained in SRP Section 3.6.3 and NUREG-1601 Volume 3. This guidance states that LBB analyses should: a) demonstrate that margin exists between the "critical" flaw size and a postulated flaw that yields a detectable leak rate; b) demonstrate that there is sufficient margin between the leakage through a postulated flaw and the leak detection capability; c) demonstrate margin on the applied load; and, d) demonstrate that fatigue crack growth is negligible. Acceptance criteria for LBB analyses include: a) margin of 10 on detectable leak rate; b) margin of 2 on flaw size; and, c) margin of $\sqrt{2}$ on loads for leakage flaw size. The staff notes that the primary inputs to LBB analyses are material properties (which are functions of the materials used and temperature), internal pressure, normal operating loads, safe-shutdown earthquake (SSE) loads, and certain plant transients.

The staff notes that the principal changes associated with EPU conditions are: a) a change in RCS flow rate; b) an increase in both RCS hot and cold leg temperatures; and, c) changes in water chemistry.

In considering the effects of the changes to the RCS system environment caused by the EPU which may affect the LBB analysis, the staff finds that: a) water chemistry changes will not affect the LBB analysis significantly; b) changes in hot and cold leg temperatures may affect material properties; c) changes in fluid flow and changes in hot and cold leg temperature may change normal operating loads; d) internal pressure for the LBB analysis will not change because system pressure does not change as a result of the EPU; and, e) SSE loads will not change as the characteristics of the SSE are not affected by the EPU.

The staff notes that the original analysis conservatively utilizes stress strain properties for 650 ^{o}F and fracture toughness properties for 550 ^{o}F. Since the change in temperature as a result of the EPU remains within these bounds, the staff finds that the actual changes in material properties resulting from the EPU do not affect the original LBB analysis.

In its application the licensee states that changes in normal operating loads do occur as a result of EPU conditions. However, the licensee also states that changes in normal operating loads resulting from the EPU are bounded by the normal operating loads used in the original LBB analysis because the normal operating loads originally used were selected to bound the normal operating loads at several plants. The staff finds that the loads used in the original LBB analysis bound the loads from the EPU conditions.

Based on the above analysis, the staff concurs with the licensee's assertion that the LBB analysis for the EPU conditions is bounded by the original analysis and that the LBB analysis for the EPU conditions satisfies the acceptance criteria of SRP Section 3.6.3.

The staff notes, however, that one aspect of the original LBB analysis, the existence of components and welds which are susceptible to PWSCC and which have not been mitigated, is contrary to guidance found in SRP Section 3.6.3. The staff has established precedent for accepting LBB analyses for conditions in which non mitigated, PWSCC susceptible, welds or components are present based on increased inspections performed in accordance with 10 CFR 50.55a(g)(6)(ii)(F). In this instance, the staff chooses to remain consistent with this precedent and accepts the licensee's LBB analysis despite its deviation from SRP Section 3.6.3. The staff is, however, reviewing the PWSCC issue with respect to leak before break evaluations. If necessary, changes in the staff policy on this issue will be generically addressed for all plants.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the LBB analysis for the plant and concludes that the licensee has adequately addressed changes in primary system P-T and their effects on the LBB analyses. The NRC staff further concludes that the licensee has demonstrated that the LBB analyses will continue to be valid following implementation of the proposed EPU and that lines for which the licensee credits LBB will continue to meet the requirements of GDC 4. Therefore, the NRC staff finds the proposed EPU acceptable with respect to LBB.

2.1.7 Protective Coating Systems (Paints) - Organic Materials

Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance activities. The NRC staff's review covered protective coating systems used inside the containment for their suitability for and stability under design basis loss-of-coolant accident (DBLOCA) conditions, considering radiation and chemical effects. The NRC's acceptance criteria for protective coating systems are based on (1) 10 CFR Part 50, Appendix B, which states QA requirements for the design, fabrication, and construction of safety-related SSCs and (2) RG 1.54, Rev. 2, for guidance on application and performance monitoring of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2.

The licensee stated that coatings located within the reactor containment building (RCB), which could potentially be subjected to design-basis accident (DBA) conditions, are referred to as Service Level I coatings. The primary purposes of Service Level I protective coatings are to provide corrosion protection and a suitable surface with regard to radioactive decontamination. Since Service Level I protective coatings are located within the RCB, failure to remain adhered to the surfaces to which they are applied could result in a larger than anticipated build-up of coating material debris at the containment sump strainers during a DBA. Conceivably, such a build-up could adversely impact the flow of water through the nuclear safety-related containment sump strainers and, correspondingly, the flow of water available for the safety-related function of the Emergency Core Cooling System (ECCS).

FSAR Section 6.3.2.2.2a provides the summary of the response to NRC GL 98-04, regarding potential degradation of ECCS and containment spray (CS) system due to protective coatings failure and foreign material accumulation in containment recirculation sumps after a loss-of-coolant accident (LOCA). The licensee's response to GL 98-04 is documented in a letter from J. A. Stall (FPL), *Generic Letter 98-04 Initial Response,* to NRC Document Control Desk; dated November 4, 1998, as summarized below. The NRC closed this issue for St. Lucie 2 via letter from K. N. Jabbour (NRC), *Completion of Licensing Action for Generic Letter 98-04, Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment,* to T. F. Plunkett (FPL) dated December 9, 1999.

The licensee stated work on Service Level I protective coatings are controlled as a "Special Process" in accordance with requirements of ASME NQA-1-1994, *Quality Assurance Requirements for Nuclear Applications,* and 10 CFR Part 50 Appendix B. Technical and quality requirements for procurement, surface preparation, application, surveillance, and maintenance of Service Level I protective coatings in containment are derived from an engineering specification. The licensee does not use commercial grade dedication for Service Level I protective coatings in containment. Additionally, the following inspections are discussed in the licensee's response:

1. Inspection of safeguards sump is performed every refueling outage;

2. Inspection of containment for loose debris at the end of each outage prior to restart;

3. Inspection of containment coatings at the end of each refueling outage to ensure that quantities of unqualified coatings are below acceptable limits.

Technical Evaluation

The licensee stated that although coatings typically do not perform a nuclear safety function, detachment from protected surfaces is an especially important consideration inside containment. Qualified containment coatings are required to remain intact after a design basis LOCA (DBLOCA) to avoid compromising the ECCS or safety-related CS system by plugging containment sump screens with debris. For the purposes of this review, the staff evaluated the results of the DBA qualification testing of the Service Level I coatings currently used in containment to ensure that the current DBA testing bound the anticipated conditions inside containment following a DBLOCA, post-EPU implementation.

As a result of implementing the EPU, the minimum boric acid concentration of the refueling water tank (RWT) and safety injection tanks (SITs) will be increased by 180 ppm, which will result in slightly reducing the anticipated maximum sump pH during a DBLOCA. No modifications to the CS system or the associated iodine removal system will be made as a result of the EPU. The maximum boric acid concentration in the RWT and the SITs is not changing as a result of the EPU; therefore, the minimum containment sump pH will remain approximately 7. Based on the planned changes to the CS system, the licensee stated that the slight chemistry changes resulting from the EPU will have a negligible impact on the Service Level I coatings inside containment.

The Service Level I coatings were qualified to a temperature of 286 °F from zero to 2.8 hours and 219 °F from 2.8-23.9 hours during DBA qualification testing. The anticipated temperature in containment following a DBLOCA at EPU conditions is 267 °F from zero to 2.8 hours, and 209 °F from 2.8-23.9 hours. The maximum pressure during the DBA qualification testing of the Service Level I coatings was 54 pounds per square inch gauge (psig), while the anticipated pressure in containment following a DBLOCA at EPU conditions is 43.48 psig. The maximum cumulative dose during the DBA qualification testing of the Service Level I coatings was 3×10^8 Rads, while the anticipated cumulative dose in containment following a DBLOCA at EPU conditions is 1.42×10^8 Rads. In all the above cases, the staff agrees that the DBA qualification testing bounds the anticipated changes in the chemistry, temperature, pressure and radiation in containment, following a DBLOCA at EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU 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 EPU and will continue to meet the requirements of 10 CFR Part 50, Appendix B. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protective coatings systems.

2.1.8 Flow-Accelerated Corrosion

Regulatory Evaluation

Flow accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to single-phase or two-phase water flow. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing even small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on flow velocity, fluid temperature, steam quality, oxygen content, and pH. During plant operation, it is not normally possible to maintain these parameters in a regime that minimizes FAC; therefore, loss of material by FAC can occur. The NRC staff reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee's FAC program to predict the rate of material loss so that repair or replacement of damaged components could be made before reaching a critical thickness.

The licensee's FAC program is based on NUREG-1344, NRC GL 89-08, and the guidelines in EPRI Report NSAC-202L-R2 & R3 "Recommendations for an Effective Flow-Accelerated Corrosion Program" dated April 1999 and August 2007 respectively. The FAC program predicts loss of material using the CHECWORKS™ computer code, as well as visual inspection and volumetric examination of the affected components. The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

Technical Evaluation

The licensee stated that the FAC program predicts, detects, monitors, and mitigates FAC in high energy carbon steel piping associated with the main steam, extraction steam, main FW, heater drains and blowdown systems, and is based on industry guidelines and experience. The licensee also stated that the FAC program addresses internal loss of material of drain lines and selected steam trap lines due to flow accelerated corrosion.

The licensee stated that large bore piping systems that are susceptible to FAC and meet the minimum criteria for effective modeling are analyzed using the EPRI computer code CHECWORKS™ SFA. Inputs to the CHECWORKS™ SFA code include heat balance information (steam cycle data), water chemistry data, piping line data, and pipe material and component data. Wear rates of piping components are obtained using the wear calculation feature of CHECWORKS™ SFA. The FAC computer program also utilizes CHECWORKS™ SFA for determination of minimum predicted wall thickness at the next inspection interval. The licensee additionally stated that piping component structural calculations, where required to satisfy code requirements, are performed by site engineering.

Certain systems and pipe segments have usage and flow rates that cannot be accurately quantified because demand and operating conditions vary greatly or are controlled by a remote level, pressure, or temperature signal. These systems cannot be effectively modeled using CHECWORKS™ SFA and the licensee has categorized them as Susceptible-Non-Modeled systems. For determination of wear rates in Susceptible-Non-Modeled lines, the licensee stated that ultrasonic testing (UT) or radiography techniques (RT) inspections are performed at selected locations, usually immediately downstream of flow orifices, steam traps, control valves, etc. The five methods commonly used for determining the wear of piping components from inspection data are: (1) Band Method, (2) Averaged Band Method, (3) Area Method, (4) Moving Blanket Method, and (5) Point-to-Point Method. Although methods (1) through (4) use different approaches, the total wear is the difference between an initial/baseline thickness and the minimum measured thickness. This value is divided by the in-service life of the component to determine the wear rate. In method (5), the difference between two sets of thickness data from two different examination dates are used to determine the wear rate over the component inservice life between the dates of examination.

The licensee additionally stated that radiography is used normally in the Long-Term Flow Accelerated Corrosion Monitoring Program for small bore components and may be used on large bore components that are 8 inches in diameter or less and Schedule 40; computed radiography is not used where wear rate trending is required. For determination of wear rates in large bore Susceptible-Non-Modeled piping and components in the FAC program, the licensee stated that ultrasonic testing measurements are taken at selected locations. The licensee's FAC engineer then determines the wear rate and predicts the wall thickness at the next outage, and the time to the next inspection.

In its letter dated February 25, 2011, the licensee provided Tables 2.1.8-1 and 2.1.8-2, which compared the current wear rates of a sampling of highly susceptible lines, with post-EPU wear rates. The tables also compared predicted wall thickness with measured wall thickness at the pre-EPU wear rate. On July 26, 2011, the staff issued an RAI to obtain information on components, with nondestructive engineering testing performed, in the same or similar lines as those provided in Tables 2.1.8-1 and 2.1.8-2. In its response, dated August, 25, 2011, the licensee provided tables listing additional inspected components to supplement Tables 2.1.8-1 and 2.1.8-2.

The tables provided by the licensee showed both increases and decreases in predicted FAC wear rates; however, the staff finds the corrosion rate changes reasonable for the corresponding changes in operating conditions. Additionally, of the 29 lines with non-destructive evaluation data provided, all 29 lines (100 percent) showed that the predicted wall thickness was more conservative than the measured wall thickness, measured by UT or RT, at the current wear rate. The staff finds that the current FAC program incorporates adequate conservatism to ensure that components susceptible to FAC will be managed appropriately prior to exceeding minimum wall thickness after implementation of the proposed EPU.

The licensee also stated that, prior to the implementation of the EPU the CHECWORKS™ SFA program will be updated to reflect the EPU heat balances and the new thermodynamic flow conditions. The licensee stated that an enhanced monitoring program will be implemented to develop baseline EPU erosion rates, define inspection periodicity, predict long-term degradation rates, and perform maintenance as required.

Conclusions

The NRC staff has reviewed the licensee's evaluation of the proposed EPU on the FAC analysis for the plant and concludes that the licensee has adequately addressed the impact of changes in plant operating conditions on the FAC analysis. Additionally, the NRC staff concludes that the licensee has demonstrated 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to FAC.

2.1.9 SG Tube Inservice Inspection

Regulatory Evaluation

SG tubes constitute a large part of the RCPB. SG tube ISI provides a means for assessing the structural and leak tight integrity of the SG tubes through periodic inspection and testing of critical areas and features of the tubes. The NRC staff's review in this area covered the effects of changes in differential pressure (DP), temperature, and flow rates resulting from the proposed EPU on plugging limits, potential degradation mechanisms (e.g., flow-induced vibration), plant-specific alternate repair criteria, and redefined inspection boundaries. The NRC's acceptance criteria for SG tube ISI are based on 10 CFR 50.55a requirements for periodic inspection and testing of the RCPB. Specific review criteria are contained in SRP Section 5.4.2.2 and other guidance provided in Matrix 1 of RS-001. Additional review guidance is contained in St. Lucie 2 TS 3.4.5, Steam Generator Tube Integrity for SG surveillance, NRC RG 1.121 for SG tube plugging limits, NRC GL 95-03 and NRC BL 88-02 for degradation mechanisms; and NEI 97-06 for structural and leakage performance criteria.

Technical Evaluation

St. Lucie 2 has two replacement SGs manufactured by AREVA. Each SG has 8999 thermally treated Alloy 690 tubes with an OD of 0.75 inches and a wall thickness of 0.043 inches. During manufacturing, all tubes were hydraulically expanded at both ends over the full depth of the tubesheet. The tubesheet was drilled on a triangular pitch with 1.0-inch spacing, center-to-center. The radius of the row 1 U-bends is 4.134 inches. The U-bends in rows 1 through 15 were stress relieved after bending. Seven Type 410 stainless steel support plates (each 1.181-inches thick), which have broached trefoil holes, support the vertical section of the tubes, and four sets of antivibration bars (each 0.112 inch thick) made from Type 405 stainless steel support the U-bend section of the tubes.

The TS surveillance requirement 4.4.5.1 requires the SG tube integrity to be verified in accordance with the licensee's SG program. The licensee stated that the current SG program will continue to be utilized to assess SG tubing structural and leakage integrity following the change in SG operating conditions (temperature, steam pressure, steam and FW flow) associated with the implementation of the EPU. Additionally, the licensee conducted an evaluation to assess the effects of the EPU on SG tube integrity due to potential changes in pressure, temperature, and flow rates. In the evaluation, the licensee determined three areas where the EPU could have an effect on SG tube integrity: tube support wear, foreign objects, and corrosion degradation. The licensee stated that although process parameter changes due to the EPU may impact the initiation and growth rates of these various degradation mechanisms, the changes are considered as part of the current SG program and will be considered in future degradation and monitoring assessments.

The licensee stated that the SGs have experienced wear at the tube supports; specifically at the anti-vibration bars in the U-bend region and at tube support plates in the straight sections. The cumulative plugging fraction for both SGs is very low for all causes with only 0.089 percent in SG 2A and 0.067 percent in SG 2B. Cumulatively, there are 2042 (11.3 percent) tubes with identified tube support wear, most of which the licensee stated are very shallow in nature. The licensee stated that inspections required by the existing SG program would detect large changes easily, and more subtle changes would be detected by the evaluation of wear rates of each inspection.

The licensee stated that wear may also result from a foreign object, depending on the mass of the foreign object. Secondary side visual inspections are routinely performed in both SGs during plant outages to evaluate the effectiveness of sludge lancing and to detect and investigate any potential foreign objects. The licensee stated that through the end of Cycle 17 inspections, all known foreign objects have been removed from both SGs.

The licensee stated that for the increase in T_{hot} (increasing from 569.3 °F to 604.0 °F), the impact of the initiation of corrosion degradation is expected to be negligible based on current operating experience at the plant compared to other Alloy 690 thermally treated plants operating at higher T_{hot} conditions and for longer operating periods in terms of effective full power hours. The licensee additionally stated that the inspection scope for future tube examinations, and the continual monitoring of operating experience of other similar Alloy 690 thermally treated plants, is sufficient to establish the onset of corrosion degradation.

Finally, the licensee stated that the increase in pressure difference across the tube wall, from 1365 psi to 1400 psi, will be incorporated into the new operational assessment and repair limits at the beginning of Cycle 19, coinciding with the planned implementation of the EPU.

Conclusion

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

2.1.10 SG Blowdown System

Regulatory Evaluation

Control of secondary side water chemistry is important for preventing degradation of SG tubes. The SG 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 expected and 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 anticipated operational occurrences (AOOs) (main condenser in-leakage and primary-to-secondary leakage). The NRC's acceptance criteria for the SGBS are based on GDC 14, insofar as it 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.

Technical Evaluation

The SGBS provides for continuous blowdown between 18,900 lb/hr and 94,500 lb/hr from above the SG tube sheet from two 2-inch blowdown nozzles that are piped into a single blowdown header per SG. This continuous blowdown prevents the concentration of soluble and insoluble impurities in the SGs (in conjunction with the chemical feed and secondary sampling systems), thus preventing or minimizing the degradation of the RCPB SG tubes from the secondary side. The blowdown lines from each SG pass through the containment penetrations and containment isolation valves to the SG blowdown treatment facility where the blowdown is cooled, filtered, purified by ion exchange and sent to monitoring storage tanks prior to recycling back to the condenser or to the discharge canal. The blowdown is cooled to 120 ºF using a closed cycle cooling system that is cooled by the open cycle cooling system. The intake cooling water system provides the cooling for the open cycle HXs.

The licensee stated that the increased steam and FW flow rates at EPU conditions do not significantly affect the concentration of impurities throughout the turbine cycle nor increase the effect of the impurities on the SGs. The licensee further stated that the normal operating blowdown flow rate will remain within design limits and will continue to control chemistry as required; therefore, no changes to the SGBS design flow rates or operational modes are needed as a result of the EPU.

The licensee additionally stated that the maximum operating pressure in the secondary side of the SGs increases slightly (7.4 psi) and the maximum operating temperature is unchanged for EPU operation. The existing design P-T of the SG blowdown piping (985 psig and 550 ºF) remain bounding and do not change at EPU conditions; therefore, no modifications to the SGBS piping system, including the pumps, valves, tanks, vessels and HXs are required as a result of implementation of the EPU.

Conclusion

The NRC staff reviewed the effects of the proposed EPU on the SGBS and based on there not being a change in the blowdown flow rate, the maximum operating temperature of the system, and because the pressure at EPU conditions does not challenge the existing design pressure, the staff has determined that the SGBS will continue to perform its function post-EPU implementation. The NRC staff also has reviewed the licensee's evaluation of the effects of the proposed EPU on the SGBS and concludes that the licensee has adequately addressed changes in system flow and impurity levels and their effects on the SGBS. The NRC staff further concludes that the licensee has demonstrated that the SGBS will continue to be acceptable and will continue to meet the requirements of GDC 14 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SGBS.

2.1.11 Chemical and Volume Control System

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 RCP and pressurizer auxiliary spray, (c) controlling the boron neutron absorber concentration in the RCS, (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 ECCS in the event of postulated accidents. The NRC staff reviewed the safety related functional performance characteristics of CVCS components. The NRC's acceptance criteria are based on (1) GDC 14, insofar as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture, and (2) GDC 29, insofar as it requires that the reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in the event of AOOs. Specific review criteria are contained in SRP Section 9.3.4.

Technical Evaluation

The CVCS is described in FSAR Section 9.3.4. The system is designed to perform the following functions:

- To control the reactor coolant inventory, chemistry conditions, activity level, and boron concentration;

- Automatically divert letdown flow to the waste management system when the highest permissible water level is reached in the volume control tank (VCT);

- To provide pressurizer auxiliary spray; and

- To support containment isolation.

To perform these functions, continuous feed and bleed is maintained between the RCS and the CVCS. Water is let down from the RCS, through a regenerative HX, to minimize thermal loss from the RCS. The pressure is reduced through letdown control valves and further cooling occurs in the letdown HX followed by a second pressure reduction. Water is returned to the RCS by the charging system. The letdown flow is normally aligned to pass through the ion exchangers to remove ionic impurities. A filter removes solids, and the gases dissolved in the coolant are removed, added, or maintained in the VCT, as applicable. The boric acid concentration in the coolant is changed by the reactor makeup portion of the CVCS as required for reactivity control. The boric acid and charging portions of the CVCS perform safety-related functions for injecting boric acid into the RCS following a safety injection actuation signal (SIAS) during accident conditions or for safe shutdown of the plant. Excess coolant may be diverted into the waste management system.

In its letter dated February 25, 2011, the licensee stated that changes in NSSS design parameters that could potentially affect the CVCS design bases functions, as a result of implementing the EPU, included the increase in core power and the allowable range of RCS full-load design temperatures. The increase in core power and the allowable range of RCS full-load design temperatures may also affect the CVCS design bases requirements related to the core re-load boron requirements. Additionally, increasing the allowable range of RCS full load design temperatures may affect the heat loads that the CVCS HXs must transfer to the CCW system; and in the case of the regenerative HX, to the charging flow.

The regenerative HX cools the normal letdown flow from the RCS, which is at the RCS T_{cold} temperature. The design inlet (RCS T_{cold}) temperature of the regenerative HX is 550 °F. The licensee stated that design inlet temperature of 550 °F bounds the highest RCS T_{cold} temperature associated with the RCS no-load temperature of 532 °F. Additionally, the licensee stated that the no-load RCS temperature, letdown flow, and charging flow do not change for the EPU. The licensee further stated that although the full-load EPU T_{cold} temperature of 551 °F will increase above the current value of 548.5 °F, it is within 1 °F of the design inlet T_{cold} value and that the regenerative HX materials were evaluated and determined to be acceptable for a range of temperatures which bound the maximum EPU operating temperatures. On July 26, 2011, the staff issued RAI, to obtain amplifying information on the evaluation done on the regenerative HX materials.

In its response dated August 25, 2011, the licensee stated that the design temperature of the regenerative HX is 650 °F and that this temperature was the bounding value for the material properties of the HX. The licensee further stated that since the design temperature was higher than the maximum expected transient temperature through the HX of 551 °F, the regenerative HX materials were determined to be acceptable at EPU conditions. The staff evaluated the licensee's response and finds that the regenerative HX materials are adequate to handle the increased temperature at full load EPU conditions.

Since the performance of the regenerative HX is unchanged at EPU conditions, as discussed in the previous section, there is no effect on the performance of the letdown HX. The licensee stated that the 1 °F difference in the letdown temperature can easily be accommodated within the capability of the letdown HX cooling water temperature control valve. Therefore, the licensee concluded that acceptable letdown HX performance will be provided at the EPU conditions.

The licensee stated there are no effects on the charging and letdown flows at EPU conditions due to the temperature change. The minimum and maximum charging and letdown flows are the same as those for current operation. With no change in letdown and charging flows, the CVCS functions of maintaining the RCS inventory, supplying pressurizer auxiliary spray, and RCS chemistry control are not impacted by EPU.

The makeup system relies on the storage capacity of various sources of water, including primary makeup water and boric acid solutions from both the boric acid makeup tanks and the RWT. Primary makeup water is used to dilute the RCS boron concentration, to provide positive reactivity control, or to blend concentrated boric acid to match the RCS boron concentration during RCS inventory makeup operations. Since the flow capacity performance of the RCS makeup system is not impacted by the change in RCS conditions resulting from the EPU conditions as discussed above, the licensee stated that the EPU does not affect the capability of the makeup system to perform these system functions.

The boric acid makeup tanks and RWT provide the sources of boric acid for providing negative reactivity control to supplement the reactor control rods. The EPU is expected to have an effect on the boration requirements that must be provided by the CVCS boration capabilities. The licensee stated that the EPU analysis has determined that the increases in the boric acid makeup tank and RWT minimum concentration requirements are within the CVCS capability. The reload safety analysis checklist is designed to address the boration capability for routine plant changes, such as core reloads, and infrequent plant changes such as a plant uprating that results in a change to core operating conditions and initial core reactivity. The licensee stated that the reload safety analysis checklist (RSAC) process will ensure the boration requirements are within the boration capability.

CVCS letdown flow and charging flow are varied to control pressurizer water level and RCS inventory. The pressurizer water level is programmed as a function of power level to assist in compensating for RCS coolant contraction and expansion. The licensee indicated that this programmed level will remain as currently installed with the revised average temperature program endpoints. The licensee stated that the current setpoints for charging and letdown control remain appropriate for EPU conditions.

The portion of the expansion/contraction volume not accounted for by the pressurizer programmed level is made up by inventory from the VCT and if necessary, from safety-related borated water sources. Safety-related makeup will always be available even when the VCT is drawn down below the low-low-level setpoint. The licensee stated that the additional expansion/contraction at the EPU temperature will result in acceptable system response. Furthermore, the licensee stated that there will be a slight increase in nominal letdown temperatures which will impact the letdown flow control valve limit setpoints that maintain minimum and maximum letdown flows; however, this impact is within the design capability of the valves.

There is the potential for an increase in crud buildup due to the EPU. The licensee indicated that 40 gallons per minute (gpm) purification flow is sufficient at the current power level and that maximum purification flow is 128 gpm, which leaves adequate margin available at EPU conditions.

Conclusion

The NRC staff reviewed the effects of the proposed EPU on the CVCS and based on the estimated increase in T_{cold}, boron concentration and potential crud build up being within the design capability of the system, as well as no changes in charging flow, letdown flow, and pressurizer level control, the staff finds that the CVCS will continue to perform its function post-EPU implementation. The NRC staff also has reviewed the licensee's evaluation of the effects of the proposed EPU 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CVCS.

2.1.12 Metamic Surveillance Program

In the LAR (Reference 2), the licensee included a Metamic™ insert surveillance program to monitor the material condition of the Metamic™ inserts proposed to be installed in the unit's SFP to support the SFP criticality analysis. The staff required additional information and issued an RAI dated October 28, 2011 (ADAMS Accession No. ML112990830) and February 16, 2012 (ADAMS Accesion No. ML12048A277). The licensee's responses to those RAIs are dated December 27, 2011 and March 8, 2012.

Regulatory Evaluation

The following is the regulatory basis for the use of Metamic™:

GDC 62, "Preventing of criticality in fuel storage and handling," states that, "criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations."

According to SRP Section 9.1.2, "Spent Fuel Storage," the staff's review should ensure the compatibility and chemical stability of the materials wetted by the water in the SFP and, if applicable, in the new fuel vault and evaluate potential mechanisms that alter the dispersion of any strong fixed neutron absorbers:

A. Compatibility and chemical stability of the materials in the components wetted by water in the SFP and in the new fuel vault. If the possibility for corrosion mechanisms is detected, the existing programs for preventing or minimizing corrosion are reviewed for their applicability to control corrosion.

B. The reactivity of fuel in the SFP is controlled by plates or inserts attached to spent fuel racks containing neutron poison dispersed in a matrix. In some environments, the matrix may degrade and release the neutron poison, resulting in some reduction of neutron absorbing properties of the panels. The licensee should have a program for monitoring the effectiveness of the neutron poison present in the neutron absorbing panels.

Technical Evaluation

2.1.12.1 Metamic™ Insert Description

Metamic™ is composed primarily of Boron Carbide and Aluminum (Al 6061). Boron Carbide is the main constituent in materials known to perform effectively as neutron absorbers and Al 6061 is a marine-qualified material known for its resistance to corrosion. The licensee provided the following description of the proposed Metamic™ inserts to be used:

- The Metamic™ used for the inserts shall have a boron carbide weight percentage of 24.5 percent minimum. Alloy 6061 aluminum powder is used in the manufacture of Metamic™. The areal density of B-10 in the inserts shall be 0.0160 gm/cm^2 nominal and 0.0150 gm/cm^2 minimum.

- The overall length of the inserts will be approximately 156.5 inches. The cross-section width of the inserts will be approximately 8.3 inches square. The Metamic™ panel thickness is nominally 0.070 inches thick.

- The landing element material will be constructed from 6061-series aluminum.

- The formed Metamic™ panel will be attached to the head piece (landing element) using a pinned connection. The top flange of the formed Metamic™ panel will be sandwiched between upper and lower aluminum pieces. There are four aluminum pins, passing through holes in the top flange of the Metamic™ panel, which will be welded to the upper and lower aluminum pieces. There will be no welding of or to Metamic™.

The staff reviewed the licensee's description of the inserts to be used in the SFP and requested clarification concerning the upper limit on the boron carbide weight percentage planned on being used for the inserts in the SFP. The staff issued an RAI dated March 28, 2012.

In the response dated March 31, 2012, the licensee stated that the coupons used in the Metamic™ Surveillance Program are identical in composition and manufacturing process as the inserts. Additionally, the licensee stated that the twenty Metamic™ coupons to be installed in the SFPs (ten per unit) have been received and that the Certificate of Compliance provided with the coupons stated that the boron carbide content for each of the twenty coupons have a weight percent that ranges from 25.07 to 25.98. The licensee finally stated that none of the coupons are over 31 weight percent boron carbide.

The staff has reviewed the licensee's response and has determined that because the coupons used in licensee's surveillance program are identical in composition and manufacturing process as the inserts installed in the licensee's SFP, then the maximum boron carbide weight percent of the inserts is bounded by the maximum upper bound of the boron carbide weight percent of the coupons, which is 25.98 percent. An insert that has a boron carbide weight percent greater than the maximum upper bound of the coupons will not be properly modeled by the coupons during the surveillance testing as described in the licensee's Metamic™ Surveillance Program; therefore, it would not be appropriate for installation in the SFP. Ensuring that the boron carbide weight percent of the inserts falls within the range of the boron carbide weight percent of the coupons provides reasonable assurance that the Metamic™ inserts will perform as designed in the SFP. The staff's concern on the upper limit of the boron carbide content of the inserts is resolved.

2.1.12.2 Metamic™ Program Description

The licensee stated that the purpose of the Metamic™ insert surveillance program is to ensure Metamic™ panels continue to meet the licensing bases requirements. This will be done by confirming that physical and chemical properties of Metamic™ perform in the SFP as in the pre-installation qualification data. The surveillance program will monitor how Metamic™ absorber material properties perform over time as a result of radiation, chemical, and thermal environment found in the SFP. The specific details of the surveillance program, including the test sample size, will be incorporated into the FSAR, based on the general elements provided below:

- Visual inspection of the Metamic™ inserts.
- Physical measurement of Metamic™ coupons.
- Neutron attenuation testing of Metamic™ coupons.

2.1.12.3 Initial and Follow on Surveillance Selection

The licensee stated that the Metamic™ inserts inspected as part of the initial surveillance campaign will be selected by considering the following criteria and generally selecting the most challenging conditions:

- Results of pre-installation inspections (e.g., select inserts that have pre-existing conditions),

- Experience gained during installation (e.g., select inserts that required higher insertion or removal forces),

- Spatial variations in cooling water flow within the pool, specifically considering effects of the fuel pool cooling system suction and discharge piping, storage arrangements and the characteristics of fuel assemblies adjacent to each insert, especially heat generation rates,

- Noteworthy or unique aspects of St. Lucie fuel pool-related operating experience during the inservice interval, such as atypical water chemistry or impact by a foreign object, and

- Relevant operating experience from other plants.

Development of follow-on inspection campaigns will be determined by results from this initial ISI. Some of the same sample of inserts/coupons may be included in future ISIs.

The staff has reviewed the surveillance criteria and has determined that they are acceptable. The incorporation of operational experience from the licensee's SFP and relevant operating experience from other plants provides reasonable assurance that the inserts exposed to the most challenging conditions will be selected for inspection.

2.1.12.4 Coupons and Coupon Tree in the SFP

A coupon tree will be installed in the SFP that holds ten coupons. The coupons are identical in composition and manufacturing process as the Metamic^{TM} inserts. The coupon tree will be placed in a SFP cell in a location that will ensure a representative dose to the coupons, in addition to simulating the flow characteristics and pool chemistry. The cell location will be in Region 2 of the SFP, which typically has highly burned permanently discharged fuel. Tested coupons will not be returned to the SFP.

The licensee stated that should the Metamic^{TM} inserts no longer be required for control of neutron multiplication within the SFP (e.g., as a result of vacating the fuel pool to dry storage), insert surveillance and inspections may be terminated.

The staff reviewed the licensee's submittal concerning the placement of the coupon tree and requested additional information regarding what the licensee meant by "representative dose" and whether the placement of the coupon tree was such that the coupons experienced an environment that bounds the SFP conditions for the inserts to be used. The staff issued an RAI dated February 16, 2012.

In the response dated March 8, 2012, the licensee stated that the most important factors of consideration for deciding on the location of the coupon tree, and the characteristics of fuel assemblies in cells surrounding the cell containing the coupon tree, are the accumulated dose and the neutron flux. The licensee additionally stated that proximity to higher burned fuel will yield a higher dose, whereas positioning near higher reactivity fuel will increase the localized flux. The licensee stated that this combined effect will be achieved by placing most recent discharged assemblies in at least two of the four cells, face-adjacent to the Region 2 cell containing the coupon tree. Additionally, other cells, face-adjacent to the coupon tree, will be loaded with discharged fuel assemblies cooled for no more than 5 years with an expected burnup in excess of 35,000 megawatt-days per metric ton uranium (MWd/MTU).

The licensee stated that this configuration of the coupon tree surrounded by recently discharged assemblies, including freshly discharged assemblies in two adjacent cells without a CEA or Metamic™ insert, will create an environment that is expected to bound all inserts. The licensee stated that the environment established around the coupons would provide reasonable assurance that, if the monitoring program were to detect degradation in the coupons, proper corrective actions can be taken to mitigate the degradation of the inserts prior to any insert falling below the design requirements.

The licensee stated that Region 1 of the SFP is inappropriate for the placement of a coupon tree because no Metamic™ inserts are credited in the Region 1 configurations analyzed for in the proposed updated TSs. The licensee stated that Region 2 of the SFP, where most of the Metamic ™ inserts will be placed, is used for the storage of permanently discharged fuel assemblies with typical burnups in excess of 35,000 MWd/MTU. The licensee further stated that the assemblies in Region 2, including the assemblies placed in cells with inserts, typically remain in the same location for a period of greater than 5 years, until removed to dry cask storage. Therefore, inserts are not exposed to freshly discharged assemblies in an as severe configuration as the coupons, described above.

The staff has reviewed the licensee's response and has determined that the placement of the coupon tree bounds the environmental conditions seen by the inserts in the SFP based on the anticipated amount of burnup and storage time of fuel assemblies planned to be stored around the coupon tree. Placing the coupon tree in an environment that bounds the environmental conditions seen by the inserts in the SFP will provide reasonable assurance that any degradation experienced by the coupons will preclude possible degradation experienced by the inserts and allow the licensee enough time to take corrective actions. The staff's concerns about the coupon tree placement have been resolved.

The staff also requested additional information concerning the physical dimensions of the coupons to be used in the SFP. Specifically, the staff requested if there would be any coupons that had a formed chevron cross-section similar to the inserts used in the pool. The staff also requested if there would be coupons that simulate the potential galvanic coupling that may be seen by the inserts in the SFP. The staff issued an RAI dated February 16, 2012.

In the response dated March 8, 2012, the licensee stated that the Metamic™ coupons have a height of 8 inches by 6 inches wide, and a thickness of 0.070 inches. This is the same thickness as the Metamic™ inserts. The licensee stated that the Metamic™ coupons do not include a formed chevron cross-section; the coupons are a flat, rectangular panel. The licensee stated that because the most important physical measurement parameter is material thickness to monitor for potential swelling, and the thickness of the Metamic™ coupon is the same thickness as the Metamic™ inserts, the coupons are representative of the inserts for this critical dimensional check. The licensee further stated that the remaining coupon measurement parameters (height, width, and weight) serve a supporting role and are utilized to identify early indications of the potential onset of neutron absorber degradation; these parameters will be measured before the coupons are installed in the SFP, and subsequently checked during future coupon inspections. The licensee stated that because relative change in these measured parameters will be evaluated as part of the surveillance program, the coupons do not have to replicate the exact geometry of the inserts. The licensee additionally stated that the visual inspections of the Metamic™ inserts will be sufficient to detect evidence of galvanic coupling. Additionally, the licensee stated that visual inspection of the actual inserts rather than the coupons is the preferred method to detect any potential for galvanic coupling as they eliminate the need to simulate area ratio and proximity effects to other dissimilar materials in the SFP (fuel assemblies, SFP racks, etc.). For these reasons, the licensee stated that the Metamic™ coupons will not be used as a means to detect galvanic coupling.

The staff has reviewed the licensee's response and has determined that based on swelling being the most significant physical characteristic of concern, the chosen coupon dimensions are representative of the inserts used in the SFP, because the coupons are the same thickness and of the same material as the inserts. Additionally, the staff has determined that the licensee's method for detecting galvanic coupling is acceptable based on using the visual examination of the inserts in the SFP, rather than relying on simulating area ratio and proximity effects to other dissimilar materials in the SFP with the coupons, because the visual examination will represent actual insert conditions. The staff's concerns with the coupon physical dimensions and galvanic coupling have been resolved.

2.1.12.5 Inspections

2.1.12.5.1 Visual Inspection of the Metamic™ inserts

The licensee stated five inserts will be selected as described in section 3.4 for visual examination at 4, 8, 12, 20, and 30 years after the initial installation and physical measurement. The licensee additionally stated that the surveillance campaigns will be scheduled to avoid refueling intervals and periods when fresh fuel is stored in fuel pool racks in preparation for refueling.

The licensee stated that the visual ISI method will be a camera-aided visual examination of the insert base material, its edges, regions of the insert where base material has been formed (i.e., bent to shape), as well as any connection to the base metal. Non-welded connections will also be examined. Interior and exterior bend radii and front and back faces of the insert will be inspected. The licensee stated that the visual examination is sufficient to detect evidence of cracking, corrosion pitting or other gross damage. Inspections may be performed on inserts underwater, after they have been removed from their storage rack cell location, or inserts may be temporarily removed from the fuel pool water, if radiation and surface contamination levels permit.

The licensee stated that should insert anomalies be noted on the visual inspections, then an additional set of five inserts will be inspected. Issues identified during the visual inspections will be included in the licensee's corrective action program (CAP) for investigation and resolution.

2.1.12.5.2 Physical Inspection of the Metamic™ Coupons

In accordance with manufacturer's recommendations, the licensee stated that two coupons will be selected for physical measurement inspection at 4, 12, 20, and 30 years following initial installation of Metamic™. Measurements will include weight and physical dimensional measurements (length, width and thickness) of the coupons to confirm the absence of swelling and shrinkage.

The licensee stated that should physical inspections of the coupons result in a failure to meet acceptance criteria for thickness, then an additional two coupons will be inspected. Issues identified during physical measurements inspection will be included in the licensee's CAP for investigation and resolution.

2.1.12.5.3 Neutron Attenuation Testing of the Metamic™ Coupons

The licensee stated that two coupons will be selected for neutron attenuation inspection 4, 12, 20, and 30 years following initial installation of Metamic™. Neutron attenuation testing is required to prove a periodic validation of certain assumptions embedded in the fuel pool rack's criticality analysis, and to also confirm that the neutron absorption capability of the Metamic™ would remain unchanged throughout its service lifetime.

The licensee stated that should a coupon fail to meet acceptance criteria during neutron attenuation testing, then an additional two coupons will be tested. Issues identified during neutron attenuation testing will be included in the licensee's CAP for investigation and resolution.

2.1.12.5.4 Staff Summary of the Proposed Inspections

The staff has reviewed the three elements of the proposed Metamic™ Surveillance Program. The licensee's proposed visual examinations of the Metamic™ inserts are acceptable because they will provide an in situ indication of any material degradation happening to the inserts while in the SFP environment. The use of Metamic™ coupons for physical measurements and neutron attenuation testing is also acceptable because the results of these examinations will also give an early indication of neutron absorber degradation, as well as a loss of neutron attenuation, given that the placement of the coupons in the SFP will be bounding of the environment experienced by the Metamic™ inserts. The interval chosen by the licensee for the inspections is acceptable because earlier inspections intervals are spaced closer together, allowing the licensee to catch the onset of any degradation and take timely corrective actions sooner in the life of the inserts. In addition, the inspections performed at earlier intervals will inform later inspections providing reasonable assurance that later inspections will be more effective at detecting degradation. The staff finds that the three elements of the Metamic™ Surveillance Program are acceptable.

2.1.12.6 Acceptance Criteria

The licensee's acceptance criteria for each inspection are as follows:

- Visual Inspection:

  Any surfaced-based abnormalities, such as, through-wall corrosion/damage, bubbling, blistering, corrosion pitting, cracking, or flaking.

- Physical Measurement Inspection:

  The licensee stated that based on the manufacturer's recommendations, an increase in thickness at any point should not exceed 25 percent of the initial thickness at that point. This acceptance criterion is to monitor for swelling. The remaining measurement parameters (length, width, and weight) serve a supporting role and should be examined for early indications of potential onset of neutron absorber degradation, if any, that would suggest the need for further attention and possibly a change in the measurement schedule.

The licensee stated that baseline inspections will be performed at the fabrication facility and will include determination of Boron Carbide weight percentage, dimensional measurements, weight measurement, visual examination for any Metamic^{TM} panel defects (inclusions, cracks, etc.), and operability checks (interface with handling tool). A panel map will be made to document any observed panel defects. The results of baseline examinations will be recorded in the inserts documentation package for future availability. The licensee additionally stated that the following dimensional measurements will be made:

Dimensional Measurement	**Information Recorded**
Insert Length	As-Found Values
Metamic^{TM} panel width	As-Found Values
Metamic^{TM} thickness	As-Found Values
Metamic^{TM} panel longitudinal bond radius	Pass/Fail
Metamic^{TM} panel bend angle	Pass/Fail

- Neutron Attenuation Testing:

B-10 areal density is to be greater than or equal to 0.015 grams of B-10 per square centimeter. The licensee stated that the revised TS 5.6.1.a.7 will contain the acceptance criteria for neutron attenuation testing (ADAMS Accession No. ML11314A111). The staff has reviewed the licensee's TS submittal and finds that it adequately reflects the required B-10 areal density stated above.

The licensee stated that the failure to meet the acceptance criteria for either physical measurement or neutron attenuation testing requires investigation and engineering evaluation, along with early retrieval and measurement of two additional coupons, to provide corroborative evidence that the indicated change(s) is real. If the deviation is determined to be real, an engineering evaluation shall be performed to identify further testing or any corrective action that may be necessary.

The staff has reviewed the acceptance criteria for the three elements of the licensee's Metamic^{TM} surveillance program and finds them acceptable. The acceptance criteria for the visual inspection will provide adequate assurance that the onset of any potential degradation will be detected so that the appropriate corrective actions can be initiated by the licensee. The physical measurement inspection of the coupons, which are representative of the inserts in the SFP, will provide adequate assurance that any swelling in the coupons will be detected early enough for the licensee to take corrective actions to prevent the adverse affects of swelling in the inserts. Furthermore, the baseline inspection of the inserts will facilitate documentation of the initial conditions of the inserts, which can be used as a reference point for later inspections. The neutron attenuation testing of the coupons, which are representative of the inserts in the

SFP will provide reasonable assurance that the inserts will continue to meet the TS requirement for B-10 areal density.

Conclusion

Based on a review of the licensee's Metamic^{TM} surveillance program, the staff concludes that the Metamic^{TM} inserts proposed for use by the licensee are compatible with the environment in the SFPs. Additionally, the staff finds the proposed surveillance program, which includes visual, physical and confirmatory tests, capable of detecting potential degradation of the Metamic^{TM} material that could impair its neutron absorption capability. The implementation of the Metamic^{TM} surveillance program provides reasonable assurance that the Metamic^{TM} inserts will be able to perform their intended function and if degradation were to occur it would be detected, monitored and mitigated in maintain subcriticality in the SFP. The staff finds that the licensee's program meets the requirements of GDC 62, as well as SRP Section 9.1.2, and concludes that the use of Metamic^{TM} as a neutron absorber insert for the SFP post-EPU implementation is acceptable.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

SSCs important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. The NRC staff conducted a review of pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures. The 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 EPU may have on items (1) through (4) above. The NRC'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.

Technical Evaluation

According to the plant's CLB, St. Lucie 2 considers postulation of high energy and moderate energy pipe failures inside containment and outside containment. The St. Lucie 2 CLB postulated pipe failures in fluid systems and acceptance criteria for postulated pipe failure (break and crack) locations and the dynamic effects associated with postulated pipe failures are contained in the plant's FSAR Sections 3.6.1 and 3.6.2. The licensee's response to staff's RAI and Section 3.6F.1 of the Unit 2 FSAR shows that the effects of moderate energy piping failures inside containment are bounded by the applicable high energy pipe breaks. FSAR Section 3.6F.2.1(c) shows that cracks are postulated for moderate energy piping outside containment to occur anywhere along the subject piping. According to licensee's EPU licensing report and the licensee's response to staff's RAI, for postulating pipe failures inside containment for EPU, the licensee used guidance provided in RG 1.46, which is part of St. Lucie 2 CLB. For postulating pipe failures outside containment for EPU, the licensee used guidance provided in the A. Giambusso Letter (December 1972), which is also part of the St. Lucie 2 CLB. The licensee's responses to staff's RAIs and the EPU licensing report show that performed evaluations at EPU conditions for moderate energy and high energy piping did not result in any new pipe break or crack locations. The licensee's response also shows that the ASME Section III, 1971 edition through Summer 1973 Addenda code was used for developing stress data for postulating pipe failures inside and outside containment, which is consistent with the CLB code. The staff finds the licensee's response acceptable because assurance has been provided that the criteria and methodology used to evaluate postulation of pipe failures are consistent with the plant's CLB.

The current structural design basis of St. Lucie 2 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 associated with circumferential (guillotine) and longitudinal (slot) breaks in the RCS primary loop piping. The validity of LBB methodology under the proposed EPU conditions is contained in EPU licensing report Section 2.1.6. The staff's evaluation of LBB is documented in Section 2.1.6. In response to staff's RAI, the licensee replied that it performed stress evaluations for postulating pipe failures for the Class I branch lines connected to the RCS primary loop piping to reconcile minor changes in thermal expansion displacements and that all other loading conditions were unchanged due to EPU for these branch lines. Applicable RCS branch piping breaks are the pressurizer surge line breaks, spray and relief line breaks, high pressure safety injection line breaks, shutdown cooling (SDC) line breaks, and chemical and volume control line breaks for letdown and charging piping. The licensee's branch line piping evaluations due to EPU did not result in any new postulated pipe break locations.

The licensee considered EPU operating parameters of temperatures, pressures and flow rates in performing piping evaluations that did not result in any new or revised postulated pipe failure locations. The licensee also considered design features that protect essential equipment from the dynamic effects of pipe whip and jet impingement of postulated pipe failures and determined that operating parameters associated with EPU did not result in any load increases which would adversely impact existing pipe whip and jet impingement assessments.

In addition, the licensee evaluated the EPU impact on the issues identified and actions requested by GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design Basis Accident [DBA] Conditions." The pressure in the solid/stagnate volume of water in a piping section between inboard and outboard containment isolation valves could increase due to heating of the trapped fluid that could result from an increase in containment temperature due to a LOCA or a main steamline break (MSLB) accident conditions and adversely affect the structural integrity of related piping and penetrations. Due to this phenomenon, one of the requested actions of GL 96-06 was that licensees address overpressurization of piping systems that penetrate the containment due to fluid susceptibility for thermal expansion. According to St. Lucie 2 FSAR Table 6.2-52, thermal relief valves were provided to seven isolated piping segments penetrating containment to address thermal overpressurization concerns of NRC GL 96-06. In reference to GL 96-06, Section 6.2.4.1.2 of the FSAR states that the design of containment penetrations accommodate thermal pressurization concerns due to environmental heating of trapped fluids and that the piping penetration assemblies are designed to withstand a P-T at least equal to the containment vessel design internal P-T and to withstand the post-accident transient environment. In an RAI the staff requested that the licensee discuss the impact that the proposed EPU has on piping sections subject to thermally induced overpressurization addressed by GL 96-06. The licensee in its response indicated that plant modifications were implemented to overpressurization susceptible isolated piping sections that penetrate the containment as part of the resolution to GL 96-06 to address its concerns. The licensee in its response also stated that the proposed EPU does not introduce any new configurations, nor does it change existing procedural controls that will result in overpressurization of piping during accident conditions. The licensee further stated that no additional modifications due to EPU are required to the ones already in place as part of the resolution to GL 96-06. The staff also noted that according to the plant licensing basis the piping penetration assemblies are designed to containment vessel design temperature, which according to the EPU licensing report Tables 2.6.1-2 and 2.6.1-3 bounds the EPU containment vessel temperature due to LOCA and MSLB. Therefore, from its review of the FSAR, review of the licensee's response to staff's RAI and review of EPU licensing report Tables 2.6.1-2 and 2.6.1-3 the staff concludes that reasonable assurance has been provided that the proposed EPU will not adversely affect the structural integrity of the piping penetration assemblies and their related isolated piping segments and the modifications that FPL has implemented as part of the resolution to GL 96-06 remain valid for EPU conditions. Because the current design containment vessel design temperature bounds the EPU containment vessel temperature due to LOCA and MSLB, as stated above, the staff further concludes that the containment structural integrity is maintained. For further evaluation input of the EPU impact on the responses to GL 96-06 and on the integrity of the primary containment and subcompartments due to mass and energy (M&E) releases resulting from pipe breaks see SER Section 2.6.

The licensee, using methods and criteria from the CLB and current design basis on record, found that the pipe break evaluations for EPU 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 EPU. The staff finds the licensee's evaluations for postulated pipe failures adequate and acceptable as they meet the licensing and design basis acceptance criteria found in its FSAR.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to determinations of rupture locations and associated dynamic effects and concludes that the licensee has adequately addressed the effects of the proposed EPU on them. The 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the determination of rupture locations and dynamic effects associated with the postulated rupture of piping.

2.2.2 Pressure-Retaining Components and Component Supports

Regulatory Evaluation

The NRC staff has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the ASME B&PV Code, Section III, Division 1, ASME/American National Standards Institute (ANSI) B31.1, and GDC 1, 2, 4, 14, and 15. The NRC staff's review focused on the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The NRC staff's review covered (1) the analyses of flow-induced vibration 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.

In addition to their GDC compliance described above, St. Lucie 2 pressure-retaining components and supports were evaluated for plant license renewal. The evaluations are documented in NUREG-1779, "Safety Evaluation Report [SER] Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2," dated September 2003 (Reference 6).

Technical Evaluation

NSSS Piping, Components, and Supports

The primary systems of St. Lucie 2 is the NSSS piping, which is the RCS piping and it consists of two heat transfer piping loops connected in parallel to the reactor pressure vessel (RPV). Each loop contains one SG, two RCPs, carbon steel piping with stainless steel cladding and instrumentation. The major function of the RCS is to transport heated coolant from the RPV through the SGs and back to the RPV for reheating. The primary system also contains an electrically heated pressurizer connected to the hot leg of one of the reactor coolant loops via a stainless steel surge line. The St. Lucie 2 current design bases for NSSS piping, components and supports is contained in FSAR Sections 5.4.3, Reactor Coolant Piping; 5.4, Component and Subsystem Design; 3.9.3.1, Design Transients Used in Design and Fatigue Analyses; 3.9, Mechanical System and Components; 3.7, Seismic Design and Section 3.2, Classification of SSCs. In addition, the current design basis also includes the pressurizer surge line thermal stratification, requested by NRC BL 88-11, "Pressurizer Surge Line Thermal Stratification."

Based on review of the licensee's responses to staff RAI, all EPU required structural evaluations of NSSS piping and supports were performed in accordance with the CLB and current design basis code of record (ASME Section III) editions. The licensee also confirmed in its response that NSSS piping and support structural evaluations at EPU conditions have used allowable stress values from the current design basis analyses of record (AOR) which utilized original code of construction allowable values. This provides further assurance that allowable stress limits stated in the construction code are not exceeded for EPU loading conditions.

The licensee evaluated the existing design basis analyses for RCS loop piping and associated branch piping, RCS loop primary equipment nozzles and supports and the pressurizer surge line to assess the impact associated with the EPU implementation. In its EPU evaluations the licensee considered the NSSS design parameters shown in EPU licensing report Table 1.1-1; EPU NSSS design transients identified in EPU licensing report Section 2.2.6; Loop LOCA hydraulic forces and the associated Loop LOCA RPV motions. For the EPU program the licensee specifically evaluated:

- RCS piping system stresses
- RCS piping system LBB loads for LBB evaluation
- RCS piping system displacements at the junction of the centerline of the RCS piping and the branch nozzle connections of the branch line piping systems to the RCS, and their impact on the branch line piping systems
- Primary equipment nozzle loads
- Pressurizer surge line piping analysis, including the effects of thermal stratification
- Primary equipment support loads (RV, SGs, and RCPs)

EPU licensing report Tables 2.2.2.1-1 and 2.2.2.1-2 provide RCS maximum stress and fatigue usage summaries for CLTP and EPU with comparisons to code allowable values. The licensee has also demonstrated in its response to staff's RAI that fatigue cumulative usage factors contained in the EPU licensing report, Section 2.2, Mechanical and Civil Engineering, have been derived for the 60-year renewed operating license of the plant. The licensee's tables show that existing AOR for the pressurizer surge line remain bounding for EPU, majority of the RCS piping AOR are also bounding for EPU with the exception of two RCS locations. The RCS hot leg straight pipe and the cold leg spray nozzles have experienced approximately 6 and 22 percent increases in stress respectively due to EPU with 46 percent and 37 percent margin left respectively prior to reaching allowable value. The staff notes that all calculated stresses and fatigue usage values are within code allowable values, and, therefore are acceptable.

The licensee also evaluated the effect of the EPU temperatures and the design transients on the pressurizer surge line design basis analysis, including the effects of thermal stratification and determined that there is no significant impact and the analysis on record remains valid for EPU. Therefore, the pressurizer surge line thermal stratification remains in compliance with the NRC BL 88-11.

The licensee also evaluated primary equipment nozzle loads which were found to be acceptable for EPU. EPU licensing report Table 2.2.2.1-1 shows that EPU stresses and CUF values for RCS nozzles are within code of record allowable limits, and therefore are acceptable. The primary equipment support loads (RV supports, SG supports, RCP supports and pressurizer supports) were also evaluated by the licensee and found structurally adequate by meeting the required design basis criteria for equipment support stresses.

Fatigue evaluations are required for class 1 SSCs. Metal fatigue is a time-limited aging analysis (TLAA) identified in the renewed plant operating license evaluations and license renewal programs and is discussed in plant licensing renewal NUREG-1779, SER Section 4.3 and Chapter 18 of the St. Lucie 2 FSAR. The licensee evaluated the EPU impact on the licensing renewal TLAAs and determined that the EPU has not resulted in any change to the plant fatigue monitoring program (FMP) commitments to track, monitor and review the affect of fatigue upon impacted components. Thus, reasonable assurance is provided that the TLAA related to metal fatigue of ASME Section III, Class 1 NSSS SSCs will continue to be valid following implementation of the EPU.

NRC RIS 2008-30, "Fatigue Analysis of Nuclear Power Plant Components", identified a concern with the simplified single-stress methodology used by some license renewal applicants to perform fatigue calculations, and as input for on-line FMPs, in lieu of the ASME Code, Section III, Subsection NB, Subarticle NB-3200 method which requires to consider all six stress components. Approval of St. Lucie 2 for licensing renewal was issued prior to RIS 2008-30, see (Reference 6). Therefore, the staff requested the licensee to show compliance with ASME Section III when stress based fatigue monitoring is utilized. In its response to staff's RAI, the licensee confirmed that St. Lucie 2 does not rely on the simplified single-stress methodology described in RIS 2008-30 and that fatigue analyses for St. Lucie 2 license renewal were performed in accordance with the rules of ASME Section III, Subsection NB-3200, which considers the six stress components. For cycle monitoring, the licensee stated in its response to staff's RAI that the St. Lucie 2 FMP does not rely on an online fatigue monitoring system. Instead, it is based on the manual logging of design cycles throughout the life of the plant. The staff finds the licensee's response acceptable, as fatigue monitoring at St. Lucie 2 follows acceptable ASME Section III and industry methods.

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 power uprate.

Balance-of-Plant Piping, Components, and Supports

The licensee evaluated the balance-of-plant (BOP) piping, components and supports inside and outside containment in accordance with the current licensing and design basis criteria to assess the impact of temperature, pressure and flow rate changes that will result due to the implementation of the EPU. The licensee in its EPU evaluations of BOP safety related class 2 and 3 piping systems utilized the criteria of ASME Section III, 1971 edition through Summer 1973 Addenda, which is consistent with the St. Lucie 2 CLB (FSAR Section 3), and, therefore is acceptable. For structural integrity assessments of BOP pipe supports, the licensee utilized the AISC Manual, 7th edition, which is also consistent with the St. Lucie 2 CLB.

The EPU licensing report states that the BOP piping and support systems that were evaluated for EPU conditions included the following systems: main steam, auxiliary steam, auxiliary FW (AFW), FW, condensate, heater drains, extraction steam, circulating water, intake cooling water, CCW, SFP cooling, SG blowdown, safety injection, CS, CVCS, SDC and turbine cooling water.

The staff's review identified that the EPU licensing report does not contain BOP piping stress summaries at EPU conditions and in reference to BOP piping, EPU licensing report page 222-23 states that "Existing pipe stress analysis results remain acceptable for EPU conditions." In an RAI the staff requested that the licensee provide pipe stress summaries for piping systems affected by the proposed EPU or provide a justification if the stresses of EPU affected piping did not change. The licensee in part of its response discussed that piping systems for which in the current analyses temperatures, pressures and flow rates bound the corresponding EPU values did not require pipe stress evaluations and the existing current analyses remain valid for EPU. The licensee in its response also shows that structural evaluations of EPU affected piping systems have been completed and submitted stress summaries for the following BOP piping systems: main steam, FW, condensate, heater vents and drains, CCW, chemical and volume control and safety injection systems. For these systems the licensee performed pipe stress and pipe support evaluations using the current plant design basis and utilized computer analysis and scaling factors. The two piping systems that are mainly affected by the EPU due to operation at increased flow rates are the main steam and FW. EPU licensing report Tables 2.5.5.1-1 and 2.5.5.4-1 show that main steam and FW EPU flow rates both increase by approximately 13 percent over the CLTP flow rates. According to licensee's responses to staff's RAIs, the licensee's structural evaluations for main steam included loads from the turbine stop valve closure and the main steam isolation valve (MSIV) closure transient events for the higher EPU flow rates. Structural evaluations for the FW also included fluid transient loads associated with FW regulating valve and FW isolation valve closure events and pump trip events due to higher EPU flow rates. Force time histories from the main steam and FW transients were utilized to generate pipe loads and stresses, which were then combined with loads and stresses from other pipe loadings (due to pressure, deadweight and seismic) to produce stresses to show compliance with ASME Section III code equations and pipe reaction loads for pipe support evaluations. In FPL letter L-2012-059 (Reference 8), the licensee in its response to staff's RAI described 15 piping modifications that are required due to the EPU. In FPL letter L-2012-177 (Reference 9), the licensee identified that additional piping sections were required for the CVCS vent modification that resulted in 29 new supports. Review of the licensee's summaries, as submitted in its staff's RAI responses, show that the revised stress levels at EPU conditions are within the code of record allowable stress levels and, therefore, are acceptable. For safety related piping, the maximum EPU stress ratios (calculated over allowable) occurred in the main steam and FW systems. The maximum EPU stress ratio for the main steam is 0.91 and for the FW is 0.80, both less than the allowable stress ratio of one.

The licensee also evaluated the pipe supports of the affected systems due to the EPU increased loads using current plant design basis. The licensee found that mainly for the main steam, FW, condensate, heater drains and CVCS vents additional supports were required and several of the existing supports needed various modifications, ranging from support replacement and/or relocation to weld modifications and structural reinforcements. In FPL letters ((Reference 8) and (Reference 9)), the licensee in responses to staff's RAI provided tabulated lists of 124 pipe support modifications with modification description summaries required due to the EPU, 29 of these supports are new supports required for the CVCS vent modification. In its response, the licensee clarified that the new and replacement snubbers shown in the response table were required to accommodate revised fluid transients and vibration levels at EPU conditions on the main steam FW and condensate piping. The licensee found that pipe supports of the above EPU affected systems, including new and modified supports, meet the current plant design basis requirements at EPU conditions and, therefore, are acceptable.

The licensee evaluated loads for equipment nozzles and containment penetrations that are affected by the EPU. In its response to a staff RAI the licensee resubmitted the EPU licensing report Table 2.2.2.2-3 and Table 2.2.2.2-4 for MS and FW respectively to show final containment penetration load summaries and resulting stresses calculated for EPU. The licensee also verified that these tables contain the total loads developed from the combined loads from the inside containment and outside containment piping. The staff reviewed the licensee's response and found that the penetration calculated stresses are within the design basis allowable values, and, therefore acceptable. The maximum EPU stress ratio (calculated over allowable) for the main steam penetrations is 0.57 and for the FW penetrations is 0.64, both less than the allowable stress ratio of one. With regard to FW pump nozzles for the replacement FW pumps and their acceptability for the higher EPU fluid transient loads, the licensee's response to staff' RAI shows that the calculated pump nozzle loads for EPU are within the allowable nozzle loads contained in the FW pump specification, and, therefore acceptable.

With respect to flow-induced vibration (FIV) at the higher EPU flow rates for affected piping systems, the staff, as a result of its review of the licensee's EPU licensing report and its responses to staff's RAI, concludes the following:

For piping affected by the proposed power uprate, St. Lucie 2 has developed a plan to address FIV. 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 power uprate including main steam, extraction steam (including turbine generator gland seal and exhaust), condensate, FW and FW heater vents and drains. The method is to perform a series of pre-EPU full power level walkdowns to collect data and establish the baseline pipe vibrations. These walkdowns, the licensee calls pre-baseline walkdowns. Several pre-baseline piping vibration walkdowns that were performed in 2008, 2009, and 2010 identified vibration levels at piping locations that required further evaluation. Detailed structural analyses of piping configurations that included these locations were performed. Resulting pipe stresses from these analyses were compared with the acceptance limits (of permitted endurance limit) recommended by the ASME O&M Code Part 3, guidance of which is recommended by SRP 3.9.2, Dynamic Testing and Analysis of Systems, Structures and Components. Based on the results of these analyses, the licensee's licensing report identified that six piping modifications and three pipe support installations/modifications are required to be implemented prior to EPU. During EPU power ascension testing, observation will take place at various power level test plateaus from 25 percent to 100 percent power, to identify increased pipe vibrations and the need for additional evaluations will be determined. Acceptance criteria for all piping vibration evaluations shall be in accordance with ASME O&M S/G-2007, Part 3. The staff finds the licensee's plan to monitor FIV for this piping adequate and acceptable. This is based on the fact that 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 O&M Part 3.

With regards to thermal expansion on the issue that piping could potentially expand due to higher EPU temperatures in affected systems and impose an unanalyzed condition that could potentially overstress piping and supports or otherwise damage SSCs, the EPU licensing report identifies that during the planned baseline walkdowns to be performed for piping vibration, piping systems subjected to a temperature increase associated with EPU (such as main steam, condensate, FW, extraction steam, and heater drains) will be inspected to identify any locations where there is a potential for unacceptable thermal expansion interaction. In addition, the licensee stated that during startup of the EPU, piping systems subjected to a temperature increase will be observed to identify any unacceptable conditions. Piping that is potentially affected by vibration and thermal expansion will be included as part of the start-up testing program related to the overall implementation of EPU. The staff finds that the licensee has adequately addressed the issue that piping thermal expansion at higher EPU temperatures will not impose an unanalyzed condition that could potentially overstress the piping and supports or otherwise damage SSCs.

Based on the staff's review of St. Lucie 2 evaluations for BOP piping, components and supports for EPU as summarized above, the staff finds the licensee's methodology acceptable as it conforms to the codes of record and the plant design basis requirements. Therefore, the staff concurs with the licensee's conclusion that the BOP piping, components and supports with the planned modifications and additions will maintain their structural integrity for EPU conditions.

RPV and Supports

The RPV is the principal component of the RCS. It forms a pressure boundary to contain the reactor coolant and 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 the heated coolant and its return to the RPV for recirculation through the core.

The St. Lucie 2 RPV is cylindrical, with a welded hemispherical bottom head and a removable hemispherical, flanged and gasketed, upper head. The head flange is drilled to match the 54 vessel flange stud bolt locations. The RPV is described in St. Lucie 2 FSAR Chapter 5, Section 5.3, Reactor Vessel. The original code of construction for the RPV and its supports is the ASME B&PV Section III, 1971 Edition through Summer 1972 Addenda. The RV closure head was replaced in 2007 in accordance with the ASME B&PV Code 1989 Edition, No Addenda.

The staff reviewed the licensee's evaluation for the RPV and its supports presented in the EPU licensing report and in the licensee's responses to the staff's RAIs. The licensee performed its evaluations for the St. Lucie 2 RPV at EPU conditions in accordance with the current plant codes of record using the current design basis RV stress report. For EPU, the licensee determined new loads throughout the RCS either by analysis or were bounding used existing design basis RCS loads. The resulting loads were then used to reconcile the individual subcomponents for the EPU conditions. Stress intensity ranges and CUFs were evaluated and compared to the acceptance criteria of the current code of record, ASME, Section III, Class 1 requirements. EPU licensing report Table 2.2.2.3-1 through Table 2.2.2.3-3 provide summaries of the maximum ranges of stress intensity and maximum CUFs at critical locations (including RPV nozzles, closure head studs, CRDM nozzles, surveillance holder and flow baffle) from the RV evaluations at EPU and pre-EPU conditions. For the majority of the RPV locations the stress and CUF values remained unchanged for EPU with a slight increase in stress in two locations by less than 2.5 percent. The surveillance holder results show a maximum increase in stress for EPU by approximately 20 percent while the flow baffle experienced a maximum increase in stress for EPU by approximately 10 percent. All of the regions of the RV are shown to meet the applicable ASME class 1 limits for stresses and fatigue CUFs, and, therefore are acceptable. The licensee also evaluated the RPV structural steel supports for EPU conditions and found that the original design loads and the pre-EPU loads are bounding. Hence, the RPV structural steel supports are acceptable for EPU conditions.

As shown in SER Section 2.2.2.2.1, the licensee has also evaluated the EPU impact on the St. Lucie 2 plant licensing renewal aging evaluations approved by the NRC in NUREG-1779 and found it acceptable.

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the structural integrity of the St. Lucie 2 RPV and supports and concludes that the licensee has demonstrated that the St. Lucie 2 RPV and supports will remain structurally adequate to perform their function at EPU conditions and will continue to meet the requirements of 10 CFR 50.55a;

GDC 1, GDC 2, GDC 4, GDC 14, and GDC 15; and the code of record ASME Section III Division 1 following implementation of the proposed EPU.

Control Rod Drive Mechanism

The control rod drive mechanisms, which St. Lucie 2 refers to as the control element drive mechanisms (CEDMs), are located on top of the RPV head and are coupled to the CEAs via extension shafts. Each CEDM is capable of withdrawing, inserting, holding or tripping the CEA from any point within its travel in response to operating signals to control reactivity. The CEDMs were replaced in 2007 as part of the reactor vessel closure head replacement program. The replacement CEDMs were designed and fabricated in accordance with the requirements of the ASME Code Section III, Class 1, 1998 Edition through 2000 Addenda.

The staff reviewed the licensee's evaluation of the CEDM pressure retaining components summarized in EPU licensing report Section 2.2.2.4 and in the licensee's responses to the staff's RAI. CEDM pressure retaining components are part of the RCPB. The licensee evaluated the St. Lucie 2 structural integrity of the CEDM RCPB considering the current design AOR evaluations and the NSSS operating parameters of EPU (EPU licensing report Section 1.1) and the EPU NSSS design transients (licensing report Section 2.2.6). Applicable loadings include pressure, deadweight, seismic, thermal and transient loads. Pressure, deadweight and seismic loads are unaffected by the EPU. EPU licensing report Section 2.2.2.4, Control Rod Drive mechanisms, shows that the NSSS parameters and NSSS design transients for EPU are bounded by the parameters and transients used the current design AOR evaluations. Therefore, the staff agrees with the licensee's response to staff's RAI that reanalysis of the CEDMs for EPU conditions is not required because design conditions for the current CEDM analysis bound the EPU conditions. The staff reviewed the stress summaries presented in the EPU licensing report which show that CUFs and stress values remain unchanged for EPU and meet the ASME Code of record allowable values, and, therefore are acceptable.

The licensee, using the current plant design basis methodology to evaluate the pressure boundary components of the CEDMs, 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 St. Lucie 2 pressure boundary components of the CRDMs are structurally adequate for continuous operation under the proposed power uprate.

SGs and Supports

The St. Lucie 2 SGs were replaced in 2007 by two AREVA replacement SGs of type 89/19TI. The SGs are vertical shell and inverted U-tube type HXs. According to the FSAR Table 5.2-1, the replacement SGs (RSGs) were designed and manufactured in accordance with ASME Section III, 1998 Edition through 2000 Addenda.

The staff reviewed the licensee's SG and support evaluations presented in the EPU licensing report and in the licensee's responses to the staff's RAIs. The licensee used the current design basis codes of record to evaluate the structural integrity of the SGs' pressure boundary and SG supports for EPU conditions. Review of the licensee's presented stress and fatigue CUF summaries shows that stress intensity ranges and CUFs increased at some locations due to increased P-T variations during normal and upset operating EPU conditions. The maximum

EPU stress ratio (calculated stress intensity over ASME allowable value) on the primary side of the pressure boundary occurred at the primary head near support skirt weld at a stress ratio value of **[ ]**. On the SG secondary side the maximum stress ratio occurred at the Handhole Flange at a stress ratio value of **[ ]**, which is less than the allowable ratio value of one. Both of the above stress ratio values are also pre-EPU values at CLTP conditions. The maximum EPU fatigue CUF is reported at the location of the tubesheet blowdown holes at a value **[ ]**, approximately 1 percent higher than CLTP and less that the ASME allowable value of one. Review of the stress and fatigue evaluation summaries of the primary and secondary boundary pressure components, presented in the EPU licensing report Section 2.2.2.5, shows that stress ranges and CUFs are within the ASME Section III, Subsection NB allowable limits, and, therefore are acceptable. The licensee also evaluated the SG supports for EPU conditions and indicated that the SG support components meet the required design basis stress criteria, and therefore, are acceptable.

The licensee's evaluations of the SG tubes for FIV and tube wear due to higher EPU flow rates are summarized in EPU licensing report Section 2.2.2.5 and in the licensee's responses to the staff's RAIs. Evaluations of FIV and tube wear were performed for fluid-elastic stability and amplitudes of tube vibration due to turbulences. The licensee's established criterion for fluid-elastic stability ratio is 0.75 which provides a 33 percent margin over the NRC BL 88-02 acceptance limit of 1.0 to preclude fluid-elastic instability. The staff's review of the licensee's summary evaluations finds that for EPU, the maximum fluid-elastic stability ratio increased to **[ ]** pre-EPU value and it occurs in the U-bend region, which is less than the established allowable limit, and, therefore is acceptable. In addition, tube high cycle fatigue stresses due to random turbulence excitation from FIV are shown well below the material endurance limit, and, therefore are acceptable. The licensee also evaluated the EPU maximum expected tube wear. Review of the licensee's tube wear evaluations shows that the maximum expected tube wear at EPU conditions occurs in the U-bend region and is **[ ]** percent through-wall, which is less than the ASME Section XI driven St. Lucie 2 TS requirement of 40 percent through-wall tube wear prior to tube plugging, and, therefore acceptable. In addition, the licensee's SG Program monitors SG tube performance and provides assurance that the SG tube integrity is maintained.

With regard to the steam separators in the steam drum of the St. Lucie 2 RSGs, the licensee reviewed operating experience from plants that use similar AREVA designed SGs. EPU licensing report states that industry operating experience has shown essentially no issue with respect to FIV in the steam separation equipment used in domestic or comparable French designed PWRs, and that the steam flows at EPU conditions increase by less than 1 percent above the level for which the St. Lucie 2 RSGs were designed. The design of the dryer banks, which are of a double-pocket chevron-type design, has been extensively used in France since 1996 with no reported issues. The EPU licensing report states that visual examinations will be performed on a regular basis as part of the SG secondary side inspection program which will continue to monitor the steam separators, dryers and other steam drum internal components. In response to staff's RAI, the licensee also stated that it plans to perform a baseline visual inspection of the steam separators prior to the implementation of the EPU. The staff finds the licensee's response acceptable because operating experience has shown that there is little potential for acoustic or FIV related degradation of the steam drum components in the St. Lucie 2 RSGs and if any occurs it will be identified and corrected via planned inspections and the plant's CAP.

The staff also notes, from its review of the EPU licensing report and the licensee's responses to the staff's RAIs, that the St. Lucie 2 has an extensive loose parts monitoring system (LPMS) with procedures in place and a system of transducers and preamplifiers that could detect debris and loose parts and initiate actions to assess the condition. The sensor outputs are monitored automatically via a computer and the LPMS is permanently installed to provide in-service monitoring function during plant operation. Loose parts can potentially damage the safety-related tubes of the SGs. The licensee stated in its response that the risk of a primary to secondary tube leak due to loose part damage is managed through regularly scheduled inspection and maintenance activities, including eddy current inspections, tubesheet flushing, and foreign object search and retrieval (FOSAR). Eddy current inspections will detect tube wear due to loose parts so that the affected tubes can be plugged and/or the objects can be removed. Tubesheet flushing and FOSAR will identify parts on the top of tubesheet region so the parts can be removed and/or the affected tubes plugged if required. In addition, the EPU licensing report identifies that Unit 2 employs a fine-grid, stainless steel grating that is designed to capture loose parts introduced through incoming FW flow and prevent them from entering the tube bundle region. Thus providing added assurance that damage to the safety-related tubes is prevented.

The staff, based on its review, finds that the licensee has adequately addressed the EPU flow induced effects on the SG internals. The staff also finds that the licensee has adequately addressed the potential of loose parts generation due to EPU flow conditions on the SG internals.

The licensee, using the current plant design basis methodology has evaluated the SGs and their supports for EPU and 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 EPU at St. Lucie 2 do not adversely affect the structural integrity of the SGs and their supports.

RCPs and Supports

There are two RCPs per each RCS loop. The RCPs are installed in the RCS cold legs between the SG outlet and the RV inlet and circulate the reactor coolant through the RCS. The RCPs and their motors are supported on snubbers and springs. The current licensing and design basis for the RCPs are contained in FSAR, Chapter 5. The RCPs are designed to the requirements of ASME Section III, 1971 Edition through Summer 1973 Addenda.

The staff reviewed the licensee's evaluations for RCP and supports presented in the EPU licensing report and in the licensee's responses to staff's RAIs. The licensee evaluated the RCS piping and supports (RPV supports, SG supports, RCP supports and the pressurizer supports) for EPU parameters and EPU NSSS design transients. The staff's review of the RCS piping and supports is presented in Section 2.2.2.2.1 of this SER. NSSS performance parameters for EPU and CLTP are provided in EPU licensing report Table 1.1-1. The licensee compared and reconciled the design loads developed from EPU conditions to those used in the existing design basis AOR and demonstrated in its EPU licensing report and in its responses to staff's RAIs that no increases in the existing set of design basis loads were required with the exemption of a small increase in shear force (1,000 lbs equivalent to a 4.2 percent increase) at pumps A1 and B2 discharge nozzles, which produces an negligible increase in stress (by 4 psi). Therefore, the staff agrees with the licensee's EPU licensing report that the design basis stresses in the AOR remain bounding for EPU conditions. The licensee also evaluated the RCP supports for EPU and indicated that they meet the required design basis criteria for equipment support stresses.

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

Pressurizer and Supports

The current licensing and design basis for the pressurizer and its supports is contained in FSAR, Chapter 5. The pressurizer was designed and fabricated in accordance with the ASME Section III, 1971 Edition through Summer 1972 Addenda. In considering only the effects of thermal stratification for the pressurizer surge line, the original code of record is the ASME Code, Section III, 1986 Edition.

The licensee evaluated the pressurizer and its supports for EPU conditions summarized in EPU licensing report Section 1.1. For the EPU NSSS design transients, the licensee's summary is provided in Section 2.2.6 of the EPU licensing report. The licensee reviewed and compared the design loads developed from EPU conditions to those used in the existing design basis analyses of record and determined that the design loads from the existing analyses bound the EPU design loads. The licensee also reviewed the NSSS EPU design transients and noted that the primary side transients were either unaffected or not significantly affected, and, therefore concluded that existing pressurizer stress and fatigue analyses remain valid. The licensee also evaluated the pressurizer safety valve (PSV) and power operated relief valve (PORV) piping for EPU conditions. Based on its evaluation the licensee determined that the maximum loads in the piping segments connected to the PORV and PSV nozzles are bounded by the original design. Therefore, the staff agrees with the licensee that the nozzle loads are also bounded by the original design. The licensee also evaluated the pressurizer supports and determined that they are acceptable for EPU conditions. The licensee evaluated the RCS piping and supports (RPV supports, SG supports, RCP supports and the pressurizer supports) for EPU parameters and EPU NSSS design transients.

The licensee also evaluated the pressurizer surge line thermal stratification due to EPU changes to temperature and design transients. The staff's review found that the proposed EPU has no significant structural impact on the surge line stratification and found it to be in compliance with NRC BL 88-11.

The licensee, using the current plant design basis methodology and acceptance criteria, has evaluated the structural integrity of the pressurizer and its supports under EPU conditions. The staff, based on its review as summarized above, concurs with the licensee that the St. Lucie 2 pressurizer and its supports are structurally adequate for continued operation under the proposed power uprate.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's structural evaluations of the pressure-retaining components and their supports. For the reasons described above, the NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on the structural integrity of pressure-retaining components and their supports. Based on the above, the NRC staff further concludes that the licensee has provided reasonable assurance that pressure-retaining components and their supports are structurally adequate to perform their intended design functions under EPU conditions and remain in compliance with 10 CFR 50.55a; GDC 1, GDC 2, GDC 4, GDC 14, and GDC 15 with respect to structural integrity following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with regards to the structural integrity of the pressure-retaining components and their supports.

2.2.3 RPV Internals and Core Supports

Regulatory Evaluation

RPV internals consist of all the structural and mechanical elements inside the RV, including core support structures. The NRC staff reviewed the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for the reactor internals for normal operation, upset, emergency, and faulted conditions. These include pressure differences and thermal effects for normal operation, transient pressure loads associated with LOCAs, and the identification of design transient occurrences. The NRC staff's review covered (1) the analyses of flow-induced vibration for safety-related and nonsafety-related reactor internal 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.

In addition to their GDC compliance described above, St. Lucie 1 reactor internals components were evaluated for plant license renewal. The evaluations are documented in NUREG-1779 (Reference 6).

Technical Evaluation

The St. Lucie 2 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 power uprate are summarized in Section 2.2.3 of the St. Lucie 2 EPU licensing report. The current design basis for the RPV internals is contained in FSAR Section 3.9.5.4.1. The code of record for the RPV internals is the ASME Section III, 1971 Edition through Summer 1972 Addenda, Subsection NG.

The staff reviewed the licensee's evaluations for the RPV internals and core support structures presented in the EPU licensing report Section 2.2.3 and in the licensee's responses to the staff's RAIs. Using the code of record, the licensee evaluated critical St. Lucie 2 RPV internal components at EPU RCS conditions and revised NSSS design transients. The following most critical reactor internal components were evaluated: core support barrel, core support plate and lower support structure beams and columns, core shroud, upper guide structure, holddown ring, incore instrumentation support system, fuel alignment plate, CEA shrouds, RV level monitoring system support tube and thimble support plate. According to the licensee's response to staff's RAI, evaluations were performed to obtain thermal stresses on RVI components at EPU conditions, which changed the AOR for thermal stresses on the RVI components. The AOR was determined to be bounding for the primary stresses and it was used for EPU. The licensee also assessed the design hydraulic loads at EPU conditions and determined that they do not change at EPU conditions. Calculated stresses were combined and fatigue evaluations were performed in accordance to ASME Section III, Subsection NG. Summaries of results of these evaluations at EPU conditions, showing maximum stress intensity ranges and CUFs, are presented in EPU licensing report Table 2.2.3-1. Review of the stress and CUF summaries shows that the maximum EPU stress ratio (calculated stress intensity over allowable) occurred on an instrument tube support that reached a stress ratio value of **[ ]**, which is still less than the allowable stress ratio value of one. The summaries also show that the maximum internal structures EPU CUF occurred on the core shroud panel at a calculated value of **[ ]**, which is less than the allowable of one. The summaries show that all stresses and fatigue CUFs meet code allowable values and, therefore, are acceptable. The core shroud girth rib was the only component location that at EPU conditions exceeded the primary plus secondary stress intensity allowable limit of 3Sm, required by ASME Section III, NG-3222.2. The licensee in its response to staff's RAI has shown acceptability of this core shroud location by simplified elastic-plastic analysis which is in accordance with Subparagraph NG-3228.3, and, therefore is acceptable.

The RPV internals, including core supports, are within the scope of License Renewal. The licensee evaluated the EPU impact on the licensing renewal TLAAs and determined that the EPU has not resulted in any change to the plant FMP commitments to track, monitor and review the affect of fatigue upon impacted components. Therefore, the TLAA related to metal fatigue of ASME Section III, Class 1 components will continue to be valid following implementation of the EPU.

The licensee has demonstrated that overall, the maximum stress intensity ranges and cumulative fatigue usage factors 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 EPU do not adversely affect the structural integrity of the RPV internal components and core support structures.

Conclusion

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

2.2.4 Safety-Related Valves and Pumps

Regulatory Evaluation

The NRC's staff's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME B&PV Code and within the scope of Section XI of the ASME B&PV Code and the ASME Operations and Maintenance (O&M) Code, as applicable. The NRC staff's review focused on the effects of the proposed EPU on the required functional performance of the valves and pumps. The review also covered any impacts that the proposed EPU may have on the licensee's motor-operated valve (MOV) programs related to GL 89-10, GL 96-05, and GL 95-07. 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 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 37, GDC 40, GDC 43, and GDC 46, insofar as they require that the ECCS, the containment heat removal system, the containment atomospheric 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 other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

In its submittal dated February 25, 2011, requesting a license amendment to operate St. Lucie 2 at EPU conditions, the licensee discussed its evaluation of safety-related valves and pumps to perform their intended functions under EPU conditions. By letters dated August 18, 2011 (ADAMS Accession No. ML11231A926) and November 14, 2011 (ADAMS Accession No. ML11319A225), the licensee submitted additional information related to the LAR. The NRC staff has reviewed the licensee's evaluation of the impact of EPU conditions on safety-related valves and pumps at St. Lucie 2. This review is summarized in the following paragraphs:

In response to GL 89-10 and GL 96-05, St. Lucie 2 established a testing and surveillance program for MOVs. The NRC review of the GL 89-10 program for St. Lucie 2 was documented in NRC Inspection Report 98-06. In a letter dated June 1, 2000, the NRC attached the SE (ADAMS Accession No. ML003719896) for St. Lucie 2's response to GL 96-05, and stated that St. Lucie 2 had established an acceptable program to periodically verify the design-basis capability of the safety-related MOVs through its commitments to the Joint Owners Group Program on MOV Periodic Verification.

In its request for the EPU license amendment, the licensee described its evaluation of the MOVs within the scope of GL 89-10 at St. Lucie 2 for the effects of the proposed EPU on the following systems: Main Steam, AFW, CS, CCW, Intake Cooling Water, Shield Building Ventilation, Reactor Coolant, Chemical and Volume Control, and ECCS. The licensee's review of the affected systems indicates that the MOVs will not be outside their original design specifications under EPU conditions and the EPU conditions will have a negligible effect on the

DPs/line pressures determined during the GL 89-10 review. Additionally, the licensee stated that the EPU will not affect MOV motor terminal voltages or MOV performance due to higher ambient temperatures. Therefore, no changes were identified to the design functional requirements for all GL 89-10 MOVs. Based on the information provided by the licensees, the NRC staff determined that all MOVs will perform their safety-related function under EPU conditions.

In response to GL 95-07, St. Lucie 2 modified the SDC system gate valves by installing bypass lines around the RCS side of the valve seats to prevent pressure locking and thermal binding. This modification was reviewed and accepted by the NRC in a letter dated July 16, 1999. In its request for the EPU license amendment, the licensee stated that the EPU does not increase the chance of pressure locking or thermal binding because susceptibility was due to the gage valve design or piping configurations and not based on any system process conditions. No previous responses or conclusions with respect to GL 95-07 were changed for the EPU; therefore, the NRC staff determined that the licensee continues to abide by the GL 95-07 requirements.

St. Lucie 2 has in place a program to ensure that safety-related air-operated valves (AOVs) are selected, set, tested and maintained so that the AOVs will operate under normal, abnormal, or emergency operating design basis conditions. Furthermore, the AOV Program ensures continued AOV reliability for the life of the plant. The AOV program includes the following categorization of AOVs:

Category 1 – AOVs that are safety-related, active, and have high safety significance

Category 2 – AOVs that are active and have safety-related or have a quality-related function, but do not have high safety significance

Category 3 – All remaining AOVs that are deemed to have significance at St. Lucie 2 with respect to operation/generation impact, plant performance, unit efficiency, etc. The licensee evaluated AOVs in the following systems for EPU conditions: Main Steam, SG Blowdown, Containment Purge, Continuous Containment Purge/ Hydrogen Purge, Containment Isolation, CS, CCW, Intake Cooling Water, Waste Management, Containment Vacuum Relief, Reactor Coolant, Chemical and Volume Control, Low Pressure Safety Injection, High Pressure Safety Injection, SDC. The results of the evaluation showed that the following AOVs require additional analysis for EPU conditions:

MSIVs – The licensee stated that the safety-related close stroke of the balanced disc globe valve with a pilot disc has an increasing maximum expected DP (MEDP) beyond the current analysis. The licensee stated that the closing margin remains adequate for the safety-related close stroke. The licensee calculates the DP to be negative (i.e. assists in the closing motion for both current and EPU conditions due to valve design), so the DP load is set to zero. The closing margin for the valve main disc is calculated to be 960.5 percent for both current and EPU conditions. The closing margin for the valve pilot disc is 305.6 percent at EPU conditions, reduced from 309.9 percent at current conditions, a 1 percent margin reduction. The NRC staff determined that this margin reduction is acceptable because the MSIVs use steam flow to assist in closure and the valve margin is very large.

SG Blowdown Containment Isolation Valve – The licensee stated that the safety-related close stroke has an increasing MEDP beyond the current analysis. The licensee stated that the closing margin remains adequate for the safety-related close stroke. This closing margin is calculated to be 6.3 percent at EPU conditions, reduced from 7.2 percent at current conditions, a 12.5 percent margin reduction. The NRC staff determined that this margin reduction is acceptable because the overall closing margin was reduced by less than 1 percent, the static tests performed by the licensee demonstrated a 10 percent margin, and the seating load is accounted for in the margin calculation, resulting in a conservative calculation.

The EPU does not affect any other AOV program valves since the current MDEP/line pressures are bounded under EPU conditions. Additionally, the results of an updated Probabilistic Risk Assessment will be used to determine any needed changes to either the risk category of AOVs or periodic verification requirements as a result of the EPU. The licensee noted that as a result of the increased flows at EPU conditions, the following additional valve changes need to be made:

- The Main Steam Safety Valves (MSSVs) as-found setpoint tolerances, currently +1/-3 percent, will be changed to ±3 percent for MSSVs with a nominal setpoint of 1000 psia and +2/-3 percent for MSSVs with a nominal setpoint of 1040 psia. The current MSSV nominal setpoints, 1000 pisa and 1040 pisa, will remain unchanged for the EPU. This tolerance change is acceptable because the MSSVs were designed to hold a ±3 percent tolerance. The +2 percent limit for the 1040 psia setpoint MSSVs is due to the overpressure analysis.

- Containment Sump Outlet Isolation Valve – The licensee stated that the safety-related open and close strokes have an increasing MEDP beyond the current analysis. The licensee stated that the opening and closing

- Margins remain adequate for the safety-related open and close strokes. The opening margin for valve 2-MV-07-2A is calculated to be 178 percent at EPU conditions, reduced from 207 percent at current conditions, a 14 percent margin reduction. The opening margin for valve 2-MV-07-2B is calculated to be 100 percent at EPU conditions, reduced from 115 percent at current conditions, a 13 percent margin reduction. The closing margin for valve 2-MV-07-2A is calculated to be 112 percent at EPU conditions, reduced from 137 percent at current conditions, an 18 percent margin reduction. The closing margin for valve 2-MV-07-2B is calculated to be 55 percent at EPU conditions, reduced from 67 percent at current conditions, an 18 percent margin reduction. The NRC staff determined that these reduced margins are acceptable because each margin continues to exceed the required torque for each safety-related open and close stroke by 50 percent or more.

The EPU does not affect any check valves in the following systems: chemical and volume control, high pressure safety injection, low pressure safety injection, CS, AFW, CCW, intake cooling water, and steam supply to the steam-driven AFW pump.

Additionally, the containment leakage rate testing program (Appendix J) will be revised due to the increase of the peak calculated containment internal pressure for the DBLOCA from 41.8 psig to 43.48 psig. The impact of the peak containment pressure increase on the stroke times was evaluated for the following containment isolation valves communicating with the containment atmosphere: containment purge supply and exhaust, primary makeup water containment isolation, service air containment isolation, instrument air containment isolation, nitrogen supply to containment, RCP cooling water supply and return, containment vent header, reactor cavity sump pump discharge, reactor drain tank pump suction, hydrogen sampling inlet and outlet, containment atmosphere radiation monitoring, containment vacuum and continuous containment purge/hydrogen purge system containment isolation. The St. Lucie 2 containment design pressure of 44 psig is greater than the DBLOCA pressure of 43.48 psig; therefore, the increased pressure will not affect these containment isolation valves.

The licensee evaluated the following safety-related pumps: boric acid makeup, charging, high pressure injection, low pressure injection, AFW, CCW, intake cooling water, CS, diesel fuel oil transfer, diesel fuel electric priming, diesel soak back lube oil AC, diesel soak back lube oil DC, diesel turbo charger lube oil AC, and diesel turbo charger lube oil DC. The licensee determined that no changes in pump designs or pump head performance are required at the EPU conditions. Based on the licensee's evaluations, the NRC staff determined that the IST Program requirements for these pumps will not be affected by the EPU.

Unrelated to the EPU, the licensee has submitted a TS change to require that the Emergency Diesel Generators (EDGs) operate at a steady-state frequency of 60 ± 0.6 Hertz (±1 percent). For valves with a specified maximum stroke time, the licensee determined that the new current/referenced stroke times will not exceed the specified maximum stroke times of the valves and stated that the IST program valve stroke time acceptance criteria values will be updated during EPU implementation. The licensee stated that the frequency tolerance change potentially impacts the IST program pump test acceptance criteria, but no modifications to IST program pumps will occur, and that the pump test acceptance values will be updated during the EPU implementation. Additionally, the submitted TS change required that the EDGs operate at a steady-state voltage of 4160 ± 210V (±5 percent). The licensee stated that the new voltage tolerance will not affect MOV AC motors or the minimum motor terminal voltage values used in determining MOV motor torque values under degraded voltage conditions. The NRC staff determined that these changes to EDG frequency and voltage are acceptable because the only resultant modifications to the IST program and hardware are administrative.

In its submittal, the licensee described its review of the IST Program for safety-related pumps and valves at St. Lucie 2 for EPU operations. The Code of Record for St. Lucie 2 is the 2001 Edition through 2003 Addenda of the ASME O&M Code and its fourth 10-year IST interval began on February 11, 2009 and ends on February 10, 2018. The scope of and the testing frequencies for components in the IST program at St. Lucie 2 will not be affected by the EPU, and the St. Lucie 2 IST program will be updated to account for the EPU setpoint changes. The licensee stated that the safety-related valves and pumps in the IST Program will continue to meet the CLB with respect to the requirements of 10 CFR Part 50 Appendix A Criterion: GDC 1, GDC 37, GDC 40, GDC 43, GDC 46, GDC 54, and 10 CFR 50.55a(f) following implementation of the proposed EPU.

The NRC staff reviewed the impact of EPU on safety-related pumps and valves, the IST program, associated testing requirements, and acceptance criteria and has concluded that the modifications and additions described above are acceptable for the normal, transient, and accident EPU operating conditions.

Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps and concludes that the licensee has adequately addressed the effects of the proposed EPU on safety-related pumps and valves. The NRC staff further concludes that the licensee has adequately evaluated the effects of the proposed EPU on its MOV programs related to GL 89-10, GL 96-05, and GL 95-07, and the lessons learned from those programs to other safety-related power-operated valves. Based on this, 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, GDC 54, and 10 CFR 50.55a(f) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to safety-related valves and pumps.

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

Regulatory Evaluation

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

In addition to their GDC compliance described above, the seismic and dynamic qualification of mechanical and electrical equipment was evaluated for St. Lucie 2 License Renewal to identify which components required an aging management review. NUREG-1779 contains the staff's SER related to the License Renewal of St. Lucie 1 and 2, dated September 2003 (Reference 6).

Technical Evaluation

The staff has reviewed the licensee's evaluations for the seismic and dynamic evaluation of the mechanical and electrical equipment presented in EPU licensing report Section 2.2.5. At EPU conditions, the seismic design inputs remain unchanged. Therefore, the staff concurs with the licensee that the proposed power uprate does not affect the seismic qualification of essential equipment. The staff's review of the St. Lucie pipe break evaluation for the proposed EPU is contained in Section 2.2.1 of this SER, where it is shown that pipe break evaluations at EPU 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 and pipe whip remain valid for the proposed EPU. Therefore, the staff concurs with the licensee that the EPU will have no adverse impact on essential equipment as a result of pipe whip and jet impingement. In Section 2.2.2.1 of this SER, the staff's review shows that there is no adverse impact in the structural integrity of NSSS piping, components and supports due to the dynamic effects of the EPU. Also, the staff's review in Section 2.2.2.2 shows that there is no adverse impact in the structural integrity of balance of plant piping, components and supports due to the dynamic effects of the EPU.

Seismic and dynamic qualification of mechanical and electrical equipment is within the scope of License Renewal. The licensee's evaluation of the EPU effect on the seismic and dynamic qualification of mechanical and electrical equipment determined that no new aging effects requiring management are identified due to EPU and no changes are necessary to any existing AMPs due to EPU. In addition, the licensee determined that the proposed EPU does not introduce any new system or component functions nor does it change the functions of existing components such that License Renewal system boundaries are affected. Furthermore, the licensee determined that the EPU has not resulted in any change to the plant FMP commitments to track, monitor and review the affect of fatigue upon impacted components. Therefore, the TLAA related to metal fatigue of ASME Section III, Class 1 components will continue to be valid following implementation of the EPU.

The licensee has also evaluated the plant changes proposed for the EPU and ensured that there are no additions to the scope of non-safety-related SSCs, whose failure could prevent the satisfactory accomplishment of a function required by 10 CFR 54.4(a)(1) and (a)(3).

Conclusion

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

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

Regulatory Evaluation

Environmental qualification (EQ) is required for certain electrical equipment to demonstrate that the equipment is capable of performing its safety function under significant environmental stresses during and following design basis events. Electrical equipment important to safety is described in 10 CFR 50.49(b), which includes: (1) safety-related electrical equipment, (2) nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions, and (3) certain post-accident monitoring equipment. The NRC staff's review focused on the effects of the proposed EPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, AOOs, DBAs. The NRC 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 EPU. The NRC's acceptance criteria for EQ of electrical equipment are based on 10 CFR 50.49, which sets forth requirements for the qualification of electrical equipment important to safety that is located in a harsh environment. Specific review criteria are contained in SRP Section 3.11.

Technical Evaluation

Reactor Containment Building (RCB) Environmental Parameters and Evaluation

EQ of electrical equipment located inside the RCB is based on MSLB, LOCA, and normal plant operation conditions and evaluation of resultant peak temperature, peak pressure, humidity, radiation, and submergence consequences. The peak temperature values for the DBAs bound the temperature transients of the AOOs. In the LAR, the licensee stated that St. Lucie 2 was originally required to meet the Institute of Electrical and Electronics Engineers (IEEE) Standard (Std.) 323-1971, "IEEE Trial-Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations," for the EQ of equipment. In February 1983, the requirements for the EQ of electrical equipment were codified in 10 CFR 50.49. This section required all holders of an operating license issued prior to February 22, 1983, to develop and complete a program for the qualification of equipment subject to 10 CFR 50.49 by the end of the second refueling outage after March 31, 1982, or by March 31, 1985, whichever came first. Pursuant to the requirements of 10 CFR 50.49, the licensee established a program for qualifying the electrical equipment defined in paragraph (b) of 50.49. Based on the information provided in the LAR, the staff verified that the normal operating conditions such as temperatures, pressure, humidity, and radiation will continue to be bounded by the pre-EPU parameters used in the licensee's EQ analyses. The accident temperature, pressure, submergence, and radiation are discussed as follows.

The staff noted that the containment LOCA and MSLB accident temperature and pressure profiles in Figure 2.3.1-1 and 2.3.1-2 of the LAR do not appear to have adequate EQ margins recommended by IEEE Std. 323-1974, "IEEE Standard for Qualifying Class 1E equipment for Nuclear Power Generating Stations." In response to the staff's RAI regarding EQ margins per IEEE Std. 323-1974, the licensee stated in letter dated October 31, 2011, that each environmental parameter value with the potential of being impacted by EPU, specifically, temperature, pressure, and radiation were evaluated to ensure the recommendations of

IEEE Std. 323-1974 have been met. Whenever, the margin recommendations were not met for the peak accident values under the initial EPU screening for a specific piece of equipment, the licensee identified that piece of equipment as an outlier. If the IEEE Std. 323-1974 margin recommendations could not be met, then alternative solutions, e.g., operating time duration, relocation, replacement, or modification were considered. In its response dated October 31, 2011, to the staff's RAI, the licensee stated that at St. Lucie 2, the above alternative solutions are required to meet IEEE Std.323-1974 margins as required by 10 CFR 50.49 under EPU conditions. The staff noted that the licensee identified two resistance temperature detectors (RTDs) (as discussed in the next paragraph) that will require replacement as a result of EPU conditions.

The staff reviewed the licensee's evaluation of EQ of the electrical equipment with respect to the increased radiation due to EPU conditions. Based on its review, the staff concluded that electrical equipment in the EQ program inside containment will remain qualified for the increased total integrated dose (TID) both inside and outside containment with the exception of the RdF Corporation RTDs TE-07-3A and TE-07-3B. EQ margin for the radiation for these containment RTDs are less than that recommended by IEEE Std. 323-1974. Based on this, the licensee stated that these containment RTDs will be replaced with RTDs that are qualified to higher dose levels that meet the radiation margin specified in IEEE Std. 323-1974. Therefore the staff finds the licensee's regulatory commitment to replace the two RTDs acceptable. The licensee included this replacement as Regulatory Commitment 4 in Attachment 7, "Regulatory Commitments," of the LAR.

The licensee's evaluation of the submergence (flooding) level during EPU accident conditions in the LAR indicated a slight decrease (approximately 1.32 inches) to the flood level and therefore determined that there is no impact on the equipment inside containment. Based on this information, the staff finds that the EQ of electrical equipment inside containment will not be adversely affected under EPU conditions with respect to submergence.

Based on the review of the LAR and licensee's supplemental information, the staff finds that the EQ of electrical equipment will remain bounding under EPU conditions inside containment.

Post Accident Operating Environmental Parameters and Evaluations

The staff reviewed the licensee's evaluation of a comparison of the current RCB EQ profiles with the EPU accident profiles for LOCA and MSLB peak temperature and pressure and subsequent temperature and pressure profiles leading to the long term Post-Accident Operability Time (PAOT) in Attachment 5 of LAR. Based on its review of the above EQ profiles, the staff noted that the EPU LOCA and MSLB profiles remain bounded by the EQ envelope following the peak temperature and pressure plateaus during and following the onset of PAOT period. As such, the staff concludes that the accidents assumed under EPU conditions do not impact the required PAOT of 180 days. Therefore, the staff finds that the PAOT of the EQ components will remain valid for EPU conditions.

Reactor Auxiliary Building (RAB) Environmental Parameters and Evaluation

EQ of electrical equipment located outside containment in the RAB is based on design basis high energy line break (HELB) and normal plant operation conditions and the resultant peak temperature, peak pressure, radiation, humidity, flooding, and pH consequences. The staff reviewed the licensee's evaluation of normal service conditions and verified that the normal operating temperatures pressure, humidity, and radiation will continue to be bounded by the pre-EPU parameters used in the licensee's EQ analyses. According to Section 2.3.1.2.2.3 in Attachment 5 of the LAR, the HELB is the basis for EQ outside containment. The licensee noted that the environmental conditions associated with HELB accidents do not change as a result of EPU operation; and therefore, all equipment outside containment remains qualified under EPU conditions. Based on its review of the licensee's evaluation, the staff finds that there is no impact on HELB due to the EPU and the EQ of equipment outside containment will not be adversely affected. In addition, the staff finds that the post-accident peak temperature and pressure will continue to be bounded by the peak temperature and pressure conditions used in the licensee's EQ analyses.

In the LAR, the licensee provided an analysis of the radiation doses under EPU conditions. The licensee's analysis predicted that two previously mild EQ zones on the 43-foot elevation of the RAB in the vicinity of the shield building ventilation system (SBVS), the High-Efficiency Particulate Air (HEPA) and charcoal filters could receive post-accident doses greater than the threshold for a harsh environment (1.0E+5 Rads) as a result of the EPU. In particular, the licensee identified eight components that were credited for post-accident mitigation in the RAB heating, ventilation, and air conditioning (HVAC) area that would receive post accident radiation doses greater than the harsh radiological environment threshold of 1.0E+05 Rads under EPU conditions. The licensee performed walk downs and further component-specific evaluations. The licensee's component-specific radiological dose evaluation determined that the resultant radiological doses were below the threshold level of 1.0E+5 Rads, thus demonstrating that the above equipment or components will remain in a mild environment and no further action was necessary. The staff reviewed the licensee's evaluation and verified that the above equipment will remain in a mild environment under EPU conditions.

Based on the above, the staff finds that the licensee has adequately demonstrated that the EQ of electric equipment will remain bounding under EPU conditions outside containment in the RAB.

Trestle Area Environmental Parameters and Evaluations

The steam trestle area is an open structure and not a closed space which reduces the challenge of temperature, pressure, and radiation to the equipment.

In the LAR, the licensee stated that there were no changes to normal and accident conditions temperature, pressure humidity, radiation due to EPU. Based on this information, the staff concludes that EQ of electric equipment will remain bounding under EPU conditions in this area.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The licensee's evaluation of the operation of the electrical components under EPU conditions to determine if there are any new aging effects requiring aging management or if any existing AMPs are affected, concluded that the EPU conditions do not result in the addition of any new or previously unevaluated materials to the system nor does it result in exceeding any operating or environmental parameters previously evaluated for components included within the scope of License Renewal. Based on its review of the licensee's evaluation, the staff concludes that changes due to EPU do not add any new or previously unevaluated materials to the system. No new aging effects requiring management are identified and no changes are necessary to any existing AMPs.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EQ of electrical equipment and concludes that the licensee has adequately addressed the effects of the proposed EPU on the environmental conditions inside and outside containment and the qualification of electrical equipment. Therefore, the NRC staff finds that with the replacement of the above mentioned RTDs with RTDs that are qualified for the respective environmental conditions, the proposed EPU is acceptable with respect to the EQ of electrical equipment and consistent with 10 CFR 50.49 requirements.

2.3.2 Offsite Power System

Regulatory Evaluation

The St. Lucie 2, offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the plant offsite power system; and the stability studies for the electrical transmission grid. The NRC staff's review focused on whether the loss of the nuclear unit, the largest operating unit on the grid, or the most critical transmission line will result in an increased probability of a loss of offsite power (LOOP) event following implementation of the proposed EPU.

The design bases of St. Lucie 2, conforms to the NRC GDC for Nuclear Power Plants as specified in Appendix A to 10 CFR Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976, in accordance with St. Lucie 2, FSAR Section 3.1.

Based on its review of the St. Lucie 2, FSAR, the staff identified the following GDC as being applicable to the proposed EPU application related to the offsite power system:

- St. Lucie 2, FSAR Section 3.1.17 Criterion 17 – Electrical Power Systems. An onsite electrical power system and an offsite electrical power system shall be provided to permit functioning of SSCs important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) SAFDLs and design conditions of the RCPB are not exceeded as a result of AOOs and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

  The onsite electrical power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

  Electrical power from the transmission network to the switchyard shall be supplied by two physically independent transmission lines (not necessarily on separate rights-of-way) designed and located so as to suitably minimize the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. Two physically independent circuits from the switchyard to the onsite electrical distribution system shall be provided. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power sources and the other offsite electrical power circuit, to assure that

SAFDLs and design conditions of the RCPB are not exceeded. One of these circuits shall be designed to be available within a few seconds following a LOCA to assure that core coolant, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electrical power from any of the remaining sources as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electrical power sources.

Technical Evaluation

The St. Lucie Nuclear Plant offsite transmission system is designed to provide reliable facilities to: 1) Accept the electrical output of the plant, and 2) Supply the plant auxiliary power system for station startup, shutdown, or at any time that auxiliary power is unavailable from the unit auxiliary transformers.

The transmission system design consists of three separate circuits connected to the plant Switchyard. One of the three 230 kilovolt (kV) transmission lines can supply all of the plant auxiliary power. The five bay 230 kV (nominal) Switchyard which is arranged in a breaker-and-a-half configuration, provides switching capability for two main generator outputs, four startup transformers (SUTs), three outgoing transmission lines, and the Hutchinson Island distribution substation.

The main generator is directly connected through a 22 kV, isolated phase bus to MTs 2A and 2B, where it is stepped up to 230 kV nominal and enters the 230 kV Switchyard through the overhead tie-lines. SUTs 1A and 2A or 1B and 2B can be fed from any one of the incoming transmission lines that serve as both incoming and outgoing lines depending on plant status. The SUTs are sized to accommodate the auxiliary loads of the unit under operating or accident conditions and power to step down the offsite voltage from 230 kV to 6.9 kV and 4.16 kV.

Grid Stability Analysis

In the LAR, the licensee provided its evaluation of the Grid Stability Analysis for the St. Lucie Nuclear power plant, Units 1 and 2, with the proposed EPU electrical output. The staff noted that the study was focused on contingency events such as whether the loss of the nuclear unit, the largest operating generating facility on the grid, or the most critical transmission line will result in a greater probability of a LOOP event occurring following implementation of the proposed EPU. The NRC's acceptance criteria for offsite power systems are based on GDC 17. Specific review criteria are contained in SRP Sections 8.1 and 8.2, and Appendix A to SRP Section 8.2. This grid stability analysis included the most-up-to date transmission model representing projected 2012 summer peak load conditions. Additional non-firm transfers were included in the model in the 2012 summer peak load case to bring the total Florida import level up to the transfer limit of 3600 megawatts electrical (MWe) representing the most conservative scenario. Based on its review of the licensee's evaluation of the grid stability analysis, the staff concluded that the thermal, voltage, and stability performance will not be degraded by EPU conditions. The transmission system and the St. Lucie plant response were stable for the contingency events simulated, and none of the plant outage event models caused transmission voltages or line loadings to exceed ratings.

Dynamic stability analysis included seven scenarios such as loss of the largest source (St. Lucie 2 generator), loss of the most critical transmission circuit (fault on the St. Lucie-Midway 230 kV number 3 line), the Midway 500/230 kV autotransformer was faulted and tripped, the Duval – Thalmann 500 kV is faulted and tripped, loss of largest load (the Andytown-Nobhill 230 kV circuit) is faulted and tripped, and the Nobhill station is isolated by tripping the Andytown-Nobhill and Conservation-Nobhill 230 kV circuits. The result of this analysis indicated a stable system response, no transmission overloads, generator reactive power overloads, or voltage problems.

System Impact Study (SIS)

The staff reviewed the licensee's response dated October 31, 2011, and the licensee's evaluation of the SIS on the FPL Transmission System due to an increase in existing capacity of the St. Lucie 1, from 905 MWe to the maximum potential cold winter output of 1052 MWe, and St. Lucie 2, from 905 MWe to the maximum potential cold winter output of 1072 MWe. The SIS included reactive power capability analyses, short circuit analyses, and dynamic stability analyses. Based on its review, the staff concludes the following:

- The fault levels at the Switchyard 230 kV will not exceed the ratings of any of the Switchyard breakers as a result of the proposed EPU.

- As a result of both St. Lucie Nuclear Plants, Units 1 and 2, planned uprates, the integration of the EPU as an FPL transmission network resource will require an increase in the thermal rating of the existing St. Lucie-Midway No. 1, St Lucie-Midway No. 2, and St. Lucie No. 3 230 kV lines from 2380 amperes (A) to 2790 A. In its response dated October 31, 2011, to the staff's RAI regarding not including this upgrade in regulatory commitments in Attachment 7 of the LAR, the licensee stated that the upgrade to the thermal rating of the existing St. Lucie-Midway No. 1, St. Lucie-Midway No. 2, and St. Lucie No. 3 230 kV lines has already been completed.

- The St. Lucie Nuclear Plants, Units 1 and 2, EPU meet the reactive capability requirements of the FPL Transmission System.

- The allowable voltage range for the St. Lucie 230 kV buses will be 230 to 244 kV with both St. Lucie units in operation, and 230 kV to 241 kV with either St. Lucie unit on start-up in accordance with FPL procedures. The licensee has established a voltage schedule of 104 percent of 230 kV that has been documented in the FPL System Operation's procedures and has been reviewed by North Electric Reliability Corporation (Reference 10).

- In its response dated October 31, 2011, the licensee stated that FPL commits to completing the modifications to remove the wave traps in the St. Lucie plant switchyard and FPL Midway substation prior to operating St. Lucie 2 at its EPU ratings. According to the licensee, this modification is scheduled for completion during the St. Lucie 1, 2011 refueling outage. The licensee documented this commitment as a Regulatory Commitment in its letter dated October 31, 2011.

The staff reviewed the licensee's evaluation of the grid stability analysis and the SIS for St. Lucie 1 and 2, considering EPU conditions and concludes that the proposed EPU will not adversely impact the stability of the grid, with implementation of switchyard and transmission system modifications, in the vicinity of St. Lucie 1 and 2 (i.e., the FPL Transmission System).

Offsite Power System Components

Transmission Lines – The licensee's evaluation determined that the 230 kV transmission lines connected to the St. Lucie Switchyard need to be upgraded by installing spacers between the existing bundled phase conductors, fiber optic overhead ground wire on all three lines, and replacement of associated disconnected switches. The proposed modifications will ensure that the transmission lines' design functions will be maintained following implementation of the EPU.

Switchyard Connections – The licensee's evaluation of the Switchyard equipment determined that it was necessary to replace wave traps with overhead fiber optic protection schemes, to replace the 230 kV Switchyard disconnect switches, and to upgrade or replace associated jumpers, buses, and equipment connections. The proposed modifications will ensure that the design functions of the Switchyard equipment will be maintained following implementation of the EPU.

MTs Tie-Line – The licensee's evaluation determined that the existing tie lines between the 230 kV Switchyard and the MTs and the associated differential protection scheme are adequate and acceptable for use under EPU conditions.

Startup Transformers Tie-Lines - The licensee's evaluation determined that the existing tie lines between 230 kV Switchyard and startup transformers high voltage side and the associated differential protection scheme are adequate and acceptable for use under EPU conditions.

The staff reviewed the licensee's evaluation of the SIS for each of the offsite power system components discussed above and concludes that the transmission lines and switchyard connections will require upgrades, as identified by the licensee, due to the increased power output of the generators. The staff also finds that the Main and Startup transformer tie lines will remain within their design ratings.

In its October 31, 2011, response to the staff's RAI, the licensee stated that FPL commits to completing the modifications to remove the wave traps in the St. Lucie plant switchyard and the FPL Midway substation prior to operating St. Lucie 2 at its EPU ratings. The licensee stated that the following modifications have already been completed: increased line ratings for the three St. Lucie-Midway lines, installation of spacers between existing bundled phase conductors, installation of fiber optic overhead ground wire on all three lines, replacement of associated disconnect switches, and installation of a power system stabilizer.

Based on its review of the LAR, the staff finds that with the licensee identified system upgrades and proposed modifications, the offsite power system will not be degraded by implementation of EPU. The staff also finds that the grid studies bound the proposed St. Lucie 2 power uprate conditions.

Impact on Renewed Plant Operating License Evaluations and License Renewal Program

The licensee evaluated the St. Lucie 2, offsite power systems that are within the scope of license renewal. The licensee's evaluation determined that the changes associated with operating the offsite system at EPU conditions do not add any new or previously unevaluated materials to the system, nor require any changes to the AMP. No new aging effects requiring management were identified. Based on the review of the licensee's evaluation, the staff finds that there is no impact on renewed plant operating license due to EPU for the offsite power system.

Conclusion

The NRC staff reviewed the licensee's assessment of the effects of the proposed EPU on the offsite power system and concludes that offsite power system will continue to meet its CLB with respect to the requirements of GDC 17 as described in St. Lucie 2, FSAR Section 3.1.17, following implementation of the modifications required to support EPU. Adequate physical and electrical separation exists and the offsite power system has the capacity and capability to supply power to all safety loads and other required equipment. The staff further concludes that the proposed EPU does not degrade the grid stability. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the offsite power system.

2.3.3 AC Onsite Power System

Regulatory Evaluation

The AC onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems that supply power to safety-related equipment. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the power system. The NRC's acceptance criteria for the AC onsite power system are based on GDC 17, insofar as it requires the system to have the capacity and capability to perform its intended functions during AOOs and accident conditions. FSAR Section 3.1 states that the design bases of St. Lucie 2, conforms with the NRC GDC as specified in Appendix A to Title 10 of *Code of Federal Regulations* Part 50 Appendix A effectively May 21, 1971 and subsequently amended July 7, 1971, and February 12,1976.

- GDC 17 as described in FSAR 3.1.17 Criterion 17 – Electrical Power Systems.

  An onsite electrical power system and an offsite electrical power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

  The onsite electrical power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

  Electrical power from the transmission network to the switchyard shall be supplied by two physically independent transmission lines (not necessarily on separate rights-of-way) designed and located so as to suitably minimize the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. Two physically independent circuits from the

> switchyard to the onsite electrical distribution system shall be provided. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power sources and the other offsite electrical power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss of coolant accident to assure that core coolant, containment integrity, and other vital safety functions are maintained. Offsite power is transmitted to the plant switchyard by three physically independent 230 kV transmission lines.

Technical Evaluation

The NRC staff reviewed the AC onsite power system and its components discussed in FSAR Sections 8.1, 8.2, and 8.3. The St. Lucie 2, AC onsite power system consists of station service transformers (SST), the 6900 volt (V), 4160 V, 480 V, 120 V systems, EDGs, associated buses, non-segregated phase bus ducts, cables, electrical penetrations (where applicable), circuit breakers, and protective relays. In addition, the main generator, isolated phase bus ducts, MTs, unit auxiliary transformers (UATs), and SUTs are included in the AC onsite power system evaluations.

Main Generator: The licensee's evaluation of the main generator rating for the St. Lucie 2, under EPU conditions concluded that the existing main generator must be modified. The required generator changes include rewinding of the rotor and stator and modifying the associated hydrogen cooling system. According to the licensee, the revised generator nameplate rating is 1200 megavolt-Ampere (MVA), 22 kV, 1080 megawatts (MW), 0.90 power factor (pf), 60 Hertz (Hz). The maximum generator output at EPU conditions will be 1069.8 MW at 0.897 pf lagging. The staff reviewed the generator capability curves and concluded that the modified main generator will be capable of continuous operation at this level and will be adequate to support unit operation at EPU conditions; including machine leading and lagging reactive power requirements. The licensee's evaluation of the main generator protection for operation at EPU conditions reveals that the existing generator protection current transformers (35,000:5 ampere rating) require replacement with new current transformers (40,000:5 ampere rating) to interface with the existing electrical protection system, and the existing main generator protection relays require revised setpoints to support operation at EPU conditions. Improved generator cooling is required and will be accomplished with the hydrogen cooler modifications. Based on its review of the licensee's evaluation of main generators, the staff concluded that with the proposed new generator rating, upgrading of its hydrogen cooling system, new current transformers, and revised generator protection relay setpoints, the main generators will be capable of performing their design function under EPU conditions.

Isolated Phase Bus (IPB) Duct: The licensee's evaluation of IPB ducts stated that the continuous current ratings of the existing IPB duct main bus and MT tap bus should be upgraded to 33.2 kilo Amperes (kA) and 16.6 kA (by upgrading the existing isolated phase coolers), respectively, which bounds unit operations at worst-case EPU loading conditions. The existing IPB duct tap buses to UAT and Potential Transformer (PT) are rated 2.5 kA (continous current rating) self-cooled. Based on the staff's review of the LAR, the staff concludes that IPB ducts for MT, UAT, and PT tap buses short circuit design ratings are less than the anticipated worst-case fault current levels for both pre-EPU and EPU conditions. According to the licensee, the IPB duct upgrade modification will include replacement of the existing isolated phase cooler. It is the staff's understanding that the IPB duct upgrade modifications are included under

Regulatory Commitment number 5 of Attachment 7 of the LAR and will be completed prior to the implementation of the proposed EPU. In its October 31, 2011, response to the Staff's RAI, regarding proposed modifications, the licensee provided the results of further evaluations of IPB taps as follows:

> MT and PT IPB taps: Worst-case fault current conditions for the MT and PT IPB taps are more severe following EPU modifications than the existing IPB configuration. The existing (pre-EPU) MT and PT IPB tap configurations are bounded by the analysis performed for EPU conditions. Therefore, these sections of the IPB system have been adequately designed to withstand the anticipated worst-case fault currents for pre-EPU conditions. Therefore, no modifications are required for the MT and PT IPB taps following EPU.
>
> UAT IPB taps: Weld a stiffener plate to the existing U-shaped channel (conductor) to limit the conductor movement and to reduce the force on the insulator. In addition, add another insulator next to the existing insulator to increase the strength. These modifications will ensure that the UAT IPB taps have adequate capacity to withstand an asymmetrical short circuit event.

Based on its review of IPB bus data provided by licensee in Table 2.3.3-1 of the LAR and the licensee's regulatory commitment for the above modifications to the IPB, the staff finds that the modified IPB will be adequate to support safe operation of the plant under EPU conditions.

<u>MTs 2A and 2B:</u> The licensee's EPU evaluation determined that the existing generator step up transformer design rating is inadequate to support unit operation at EPU conditions. As a result, the licensee performed a transformer study to determine required modifications to upgrade the MT rating from 475 MVA to 635 MVA. The required modifications include replacement of step up MTs 2A and 2B with higher rated transformers of 635 MVA each, and forced oil and air at 55 degrees Celsius (°C) temperature rise. Based on its review of the LAR, the staff finds that the licensee has demonstrated that the new MT ratings are adequate to support output of the main generator, and envelop the anticipated worst-case loading at EPU conditions. The existing MT protection requires revised relay setpoints to support operation at EPU conditions. Based its review of the LAR, the staff concludes that by upgrading the MTs ratings from 475 MVA to 635 MVA, and with revised relay setpoints, St. Lucie 2 MTs 2A and 2B will be adequate to support safe operation at EPU conditions. It is the staff understanding that the licensee has provided a regulatory commitment to upgrade the MT's ratings and revise the associated relay setpoints under Regulatory Commitment No. 5 in Attachment 7 of the LAR. The NRC staff concludes that by upgrading the MTs ratings from 475 MVA to 635 MVA, and with revised relay setpoints, St. Lucie 2 MTs 2A and 2B will be adequate to support safe operation at EPU conditions.

<u>UATs 2A and 2B</u>: The licensee's evaluation determined that the existing UAT 65^0 C design ratings for the high voltage and both low voltage windings envelope the anticipated worst-case loading on the UATs at EPU conditions, therefore, the existing UATs are adequate to support unit operation at EPU conditions. The existing UAT protection relay setpoints are not affected and are adequate at EPU conditions. The staff reviewed St. Lucie 2 FSAR Section 8.2.1.4 and the licensee's evaluation of the UATs design rating, anticipated worst case loading at EPU conditions and its associated protection relay setpoints. Based on its review, the staff finds that UAT ratings are adequate to support safe operation of the plant under EPU conditions.

SUTs 2A and 2B: In the LAR, the licensee noted that the existing SUT design ratings for the high voltage and both low voltage windings envelop the anticipated worst-case loading on the SUTs at EPU conditions, therefore, the existing SUTs are adequate to support unit operation at EPU conditions. The licensee further noted that the existing SUT protection relay setpoints are not affected and are adequate at EPU conditions. The staff reviewed St. Lucie 2, FSAR Section 8.2.1.4 and licensee's evaluation of the SUTs design rating and the anticipated worst case loading at EPU conditions. Based on its review, the staff finds that the SUT ratings and existing protection relay setpoints are adequate to support safe operation of the plant under EPU conditions.

6.9 kV AC System: The licensee's evaluation of the 6.9 kV system, switchgear buses, circuit breakers, non-segregated phase bus ducts, and affected motors at EPU conditions confirms the following:

- The calculated worst-case continuous current for each affected 6.9 kV switchgear bus and circuit breaker during maximum full load at EPU conditions is less than the equipment design ratings. The staff reviewed the bus loading data and the existing design ratings in Table 2.3.3-2 of the LAR and the licensee's evaluation of the nonsegregated phase bus duct. Based on its review, the staff concludes that the maximum full load at EPU conditions is less than the equipment design ratings. Therefore, the staff finds that the EPU loading requirements of switchgear buses, circuit breakers and nonsegregated phase bus ducts are within the equipment design ratings.

- The staff reviewed the licensee's evaluation and Table 2.3.3-4 and 2.3.3-5 for the calculated worst-case short circuit momentary and interrupting currents at the affected 6.9 kV switchgear buses during EPU operation. Based on its review, the staff finds that the affected 6.9 kV switchgear circuit breaker short circuit momentary and interrupting currents are less than the equipment short circuit ratings. Thus, the EPU short circuit current requirements of switchgear buses and circuit breakers remain bounded by equipment design ratings. Therefore, the staff finds that the 6.9 kV system switchgear buses, circuit breakers, and nonsegregated phase bus ducts are adequately sized to support operation at EPU conditions.

4.16 kV AC System: The licensee's evaluation of the 4.16 kV AC system, switchgear buses, circuit breakers, non-segregated phase bus ducts and affected motors at EPU conditions demonstrated the following:

- The calculated worst case continuous current for each affected 4.16 kV switchgear bus and circuit breaker during maximum full load at EPU conditions is less than the equipment design ratings. The staff reviewed Table 2.3.3-7 of the LAR and the licensee's evaluation of the non-segregated phase bus duct and concluded that the maximum EPU load currents are less than the equipment design ratings. Therefore, the staff finds that the EPU loading requirements of switchgear buses, circuit breakers and non-segregated phase bus ducts are within the equipment design ratings.

- The calculated worst-case short circuit momentary currents at the affected 4.16 kV switchgear buses during operation at EPU conditions are less than the equipment short circuit ratings. The staff reviewed Table 2.3.3-6 and the licensee's evaluation of the 4.16 kV switchgear circuit breaker short circuit interrupting currents and concludes that they are less than the equipment short circuit ratings. The EPU short circuit current requirements of switchgear buses and circuit breakers remain bounded by equipment design ratings. Therefore, the staff finds that the 4.16 kV system switchgear buses, circuit breakers, and non-segregated phase bus ducts are adequately sized to support operation at EPU conditions.

480 V AC System: St. Lucie 2, FSAR Section 8.3.1.1.1(c) describes the 480 V system. The 480 V AC system is comprised of nine 480 V load center buses supplied from the 4.16 kV system through 4160 V/480 V AC Station Service Transformers (SSTs) which are normally powered from the UATs or SUTs. The licensee's evaluation determined the need for the following change on the safety-related equipment under EPU conditions:

- The 25 horsepower (hp) IPB duct fan cooler motors will be replaced by 100 hp fan motors and will be removed from safety-related motor control center (MCC) 2A1 and 2B1 and repowered from 480 V safety-related load centers 2A1 and 2B1.

The licensee's evaluation of the 480 V AC system, affected SSTs, load center buses and circuit breakers, and MCCs at EPU conditions demonstrated the following:

4160 V/480 V AC SSTs: There is no increase in load on the safety-related 480 V systems under EPU conditions. The licensee's evaluation found that the affected SST design ratings envelope the load requirements under EPU conditions.

480 V Load Center Buses and Breakers: The staff's review of Tables 2.3.3-10 and 2.3.3-11 of the LAR and the licensee's evaluation of the calculated worst-case steady-state continuous current, short circuit momentary duty, and the short circuit interrupting duty of the circuit breakers at the 480 V load center buses found that they are bounded by the equipment design ratings under both existing and EPU conditions with the exception of the circuit breaker 2-40703 on load center 2AB, which is rated 22 kA (maximum fault current 24 kA). In the LAR, the licensee stated that this overduty condition will be resolved prior to EPU. The staff understands that this condition will be remedied as part of the Regulatory Commitment 5 in Attachment 7 of the LAR.

480 V AC MCCs: According to the licensee, the impact of the EPU on the affected MCC steady-state continuous load currents is a reduction in load on MCC buses 2A1 and 2B1. The licensee's evaluation of load flow calculations determined that the steady-state load current requirements for the affected MCC buses and circuit breakers are bounded by the MCC bus and circuit breaker design rating. The licensee's short circuit calculations determined that the fault duties on the circuit breakers are bounded by the equipment design ratings. The staff's review of the licensee's evaluation of the 480 V MCC steady-state load current and short circuit fault duties found that the 480 V MCC buses and circuit breakers are adequately sized for steady-state continuous current loading and short circuit duty to support plant operation at EPU condition.

480 V System Voltage Level: The licensee's evaluation demonstrated that there are no adverse voltage effects on the safety-related 480V load center buses protected by degraded voltage relays. Therefore the degraded voltage relay settings are not affected by operation at EPU conditions. The load flow calculations determined that the minimum steady-state voltages on the safety-related 480 V load centers and MCCs are above the allowable minimum design values. The staff's review of the licensee's evaluation of the degraded voltage settings and the

load flow calculations found that the maximum steady-state voltage on 480 V load centers and MCCs do not exceed the maximum allowable design value range.

480 V AC Motor Load Requirements: The IPB duct and MT tap bus upgrade will require replacement of existing 25 hp IPB duct cooler fan motors with new fan motors rated at 100 hp and the power supply will be modified to be powered from the 480 V load centers 2A1 and 2B1. The staff noted that the equipment rated loads on the existing IPB duct cooling system will increase due to these modifications. However, the staff finds that the new steady-state full load currents of the new motors will be bounded by the full load design rating at EPU conditions. Based on its review of the licensee's evaluation of the power supply requirements analysis and the load flow calculations, the staff finds that there is no adverse impact on the 480 V system from these modifications under EPU conditions.

Based on above, the staff finds that the licensee has adequately demonstrated that the 480 V system will be capable of performing its design function under EPU conditions.

EDGs

The staff reviewed St. Lucie 2, FSAR Section 8.3.1.1.1(f) and the licensee's evaluation in the LAR for the St. Lucie 2 EDG design, ratings, worst-case loading, related TSs Surveillance Requirements (SR) 4.8.1.1.2.e for voltage and frequency limits. In the LAR, the licensee stated that the continuous rating of the EDGs is 3669.4 kW with additional short term ratings of 3934.3 kW (2000 hour) and 4108.6 kW (30 minutes) at 104 ºF. EDG loading will increased as a result of EPU due to the proposed upgrades and modifications. The staff reviewed the licensee's response dated October 31, 2011, regarding adequacy for EDG rating for the EPU conditions and the licensee's evaluation to assess the impact of the EPU loads on the capacity of the EDGs. Based on its review, the staff finds that the EDG ratings are not exceeded by the cumulative loads applied, and that the output voltage and frequency can be expected to meet specified requirements when loads are added, either as part of the load blocks or individually. In addition, the staff finds that the EDG will meet the load requirements of the TS under EPU conditions. Based on the above review, the staff concludes that no modification of the EDGs is required to accommodate the increased loads. Since the EDG loading is bounded by the EDG rating, the existing protective relay settings will not be impacted by EPU.

In its response dated October 31, 2011, to the staff's RAI regarding transient capability of the diesel generator engine and generator verses maximum starting (transient) loads on the EDGs, the licensee stated that the EDG will meet the response requirements specified in the St. Lucie 2, FSAR and TS, RG 1.9, "Selection of Diesel generator Set capacity for Standby Power Supplies," March 1971 (Rev. 0), and original vendor performance parameters. The specified limits to meet the TS and RG 1.9 requirements are as follows: during transient loading the voltage will remain > 75 percent of nominal and frequency will remain $\geq$ 95 percent of nominal, with recovery to 4160 $\pm$ 420 V and 60 $\pm$ 1.2 Hz. Similarly, starting loads remain within the transient capability of the generator, and therefore, the EDG voltage remains within the specified limit.

Based on the above, the staff finds that EDG will continue to have the capability and capacity to operate under EPU conditions.

Proposed Changes to EDG TS SR relating to Steady-State Voltage and Frequency Limits

In Attachment 3 of the LAR, the licensee proposed revising TS SRs 4.8.1.1.2.e.4.b, 4.8.1.1.2.e.5.a and c, 4.8.1.1.2.e.6.b, and 4.8.1.1.2.e.7.a and b.

Currently, according to the above SRs, when started from standby conditions, each EDG is required to have steady-state voltage 4160 ± 420 V (±10 percent) and frequency 60 ± 1.2 Hz (±2 percent) during this test. The licensee has proposed revising the above TS SRs to require each EDG to achieve a steady-state voltage 4160 ± 210 V (±5 percent), and frequency 60 ± 0.6 Hz (±1 percent).

The proposed changes to steady-state frequency and steady-state voltage limits are conservative with respect to the recommendations in RG 1.9 and the existing TS. In Attachment 1 of the LAR, the licensee stated that the revised steady-state frequency, 60 ± 0.6 Hz (± 1 percent), and revised steady-state voltage, 4160 ± 210V (± 5 percent), reflect worst case values used in determining MOV and pump loads connected to the EDGs. According to the licensee, the accident analyses considered the over and under frequency and voltage uncertainty tolerance of the EDGs. The change in frequency tolerance has been evaluated by the licensee for changes in MOV stroke times and pump flow rates under EPU conditions. The licensee stated that the IST program acceptance criteria will be verified for MOVs and pump flows during the EPU Implementation Phase.

In its October 31, 2011, response to the staff's RAI, regarding confirmation that all safety-related loads powered by the EDGs with the proposed voltage and frequency limits would start and run without any damage, the licensee stated that there are EDG frequency and voltage sensing relays that have their contacts wired in series that serve as permissives to the EDG output breaker automatic close circuit. These permissives operate in conjunction with engineered safety features (ESF) bus voltage relaying permissives. Once these permissive relays are actuated, the EDG output breaker is automatically closed.

The TS allowable time duration from the initiation of the EDG start sequence to the EDG output breaker closure cannot exceed 10 seconds. The EDG voltage and frequency must be in an acceptable range within 10 seconds for its associated output breaker to close in order to satisfy TS requirements. Therefore on receipt of a SIAS without a LOOP, the EDG would be expected to achieve acceptable voltage and frequency values within 10 seconds. The EDG supplied motor loads are not subjected to EDG induced voltage and frequency deviations that would inhibit their ability to perform their designed safety function for this event. The proposed change tightens the steady-state frequency and voltage tolerances, and is conservative. Based on its review, the staff finds that the proposed TS changes are conservative, and the loadings remain within the EDG capability, the staff finds the proposed changes consistent with the guidance in the SRP and Position C.1.4 of RG 1.9; and therefore, are acceptable.

<u>120 V AC Instrument Power and 120/208 V AC Power Systems:</u> The 120 V AC instrument power system and 120 V/208 V AC Power System are described in St. Lucie 2, FSAR Sections 8.3.1.1.1(d) and 8.3.1.1.1(e). In the LAR, the licensee stated that anticipated modifications are required due to EPU conditions that may affect the 120 V AC non-Class 1E and 120 V/208 V AC non-Class 1E Power Systems. The licensee stated that these modifications will be implemented as part of the plant modification process. The new load

additions from these modifications are expected to be minor, and the effect on the 120 V AC non-Class 1E and 120 V/208 V non-Class 1E power systems is expected to be small.

Based on its review of the LAR, the staff finds that the minor load additions will have minimal impact on the 120 V AC power systems licensing basis and it will not adversely impact the capacity and capability of the 120 V AC Instrument and 120/208 V AC Power Systems to perform their design functions under EPU conditions.

Impact on Renewed Plant Operating License Evaluations and License Renewal Program

The licensee evaluated the St. Lucie 2, AC onsite power systems that are within the scope of license renewal. The licensee's evaluation determined that the changes associated with operating the AC onsite power system at EPU conditions do not add any new or previously unevaluated materials to the system, nor require any changes to the AMP. No new aging effects requiring management were identified. Based on the review of the licensee's evaluation, the staff finds that there is no impact on renewed plant operating license due to EPU for the AC onsite power system.

Conclusion

The NRC staff reviewed the licensee's assessment of the effects of the proposed EPU on the AC onsite power system and concludes that the licensee has adequately demonstrated that the AC systems will be capable of performing their design functions under EPU conditions. The NRC staff further concludes that the AC onsite power system will continue to meet the St. Lucie 2 FSAR Section 3.1.17 Criterion 17 Requirements and GDC 17 following implementation of the proposed modifications as listed in the Regulatory Commitments provided in Attachment 7 of the LAR. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the AC onsite power system.

2.3.4 DC Onsite Power System

Regulatory Evaluation

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. The FPL review covered the information, analyses, and referenced documents for the DC onsite power system. The NRC acceptance criterion for this review is based on 10 CFR Part 50, Appendix A, GDC 17. It requires the system to have the capacity and capability to perform its intended functions during AOOs and accident conditions. Specific review criteria are contained in NRC SRP Sections 8.1 and 8.3.2.

St. Lucie 2, CLB

As stated in FSAR Section 3.1, the design bases of St. Lucie 2, conforms with the NRC GDC for Nuclear Power Plants, 10 CFR Part 50, Appendix A effective May 21, 1971 and subsequently amended in July 7, 1971 and February 12, 1976. The adequacy of the St. Lucie 2, design relative to the GDC is discussed in FSAR Section 3.1. Specifically, the adequacy of the DC onsite power system design relative to GDC 17 is described in FSAR Section 3.1.17 as follows:

> An onsite electrical power system and an offsite electrical power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents. The onsite electrical power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure. Provisions shall be included to minimize the probability of losing electrical power from any of the remaining sources as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network or the loss of power from the onsite electrical power sources.

In the event of a loss of the offsite power sources, two emergency onsite diesel generator sets and redundant sets of station batteries provide the necessary AC and DC power for safe shutdown or, in the event of an accident, provide the necessary power to restrict the consequences to within acceptable limits. The onsite emergency AC and DC power systems consist of redundant and independent power sources and distribution systems such that a single failure does not prevent the systems from performing their safety function.

Technical Evaluation

The staff reviewed the licensee's evaluation of the safety-related 125 V DC Systems to determine potential impacts due to EPU conditions.

According to the licensee, there are two plant modifications that are planned to be implemented for St. Lucie 2 that will affect the safety-related portions of the 125 V DC System as follows:

1. The first modification changes the power sources for IPB duct cooling fans from 480 V AC MCCs to 480 V AC load centers. The circuit breakers for the 480 VAC load centers utilize DC control power, which will increase the loading of the 2A and 2B batteries.

2. AC buses margin improvement modifications – These modifications trip IPB duct cooling fan motors, MT cooling equipment, condensate, FW, and heater drain pump motors on the SIAS event. The control circuit for all these breakers utilizes DC control power that will increase the loading on the 2A and 2B batteries.

The licensee compared the EPU load increases on the 2A and 2B batteries with the first minute's loading (most conservative approach) under the SBO coping and SIAS scenarios and a percent increase was calculated. The most limiting case (i.e., the case with least amount of available margin) was the SBO coping case. However, the EPU DC load increases on 2A and 2B batteries affect only SIAS scenarios. The staff reviewed the licensee's response dated October 31, 2011, and its evaluation in the LAR on the station battery capacity and finds that the SBO coping battery 2A and 2B margins have not changed as a result of EPU. For Battery 2A under SIAS scenarios, the additional first minute loading associated with EPU conditions (10.0 A) represents a 1.6 percent load increase, with a pre-EPU margin of 28.8 percent. For Battery 2B under SIAS scenarios, the additional first minute loading associated with EPU conditions (10 A) represents a 1.6 percent load increase, with a pre-EPU margin of 25.9 percent.

Based on its review, the staff concludes that that the 125 V DC System will continue to have the capacity and capability to perform its design function and will remain within equipment ratings while maintaining adequate margin for battery capacity. Separate and independent station battery systems are maintained to supply power to all safety loads in accordance with the CLB with respect to GDC 17. In addition, the licensee stated that SBO and 10 CFR Part 50, Appendix R program evaluations did not result in any 125 V DC System load changes.

The NRC staff reviewed the licensee's assessment of the effects of the proposed EPU on the DC onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the DC onsite power system will continue to meet the FSAR Section 3.1.17 Criterion -17 Requirements and GDC 17 following implementation of the proposed modifications as listed in the Regulatory Commitments provided in Attachment 7 of the LAR. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the DC onsite power system.

Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The licensee stated that the DC onsite power system is within the scope of License Renewal Operation, and of the DC onsite power system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing AMPs are affected. The EPU does not result in the addition of any new or previously unevaluated materials to the system nor does it result in exceeding any operating or environmental parameters previously evaluated for components included within the scope of License Renewal. Thus, no new aging effects requiring management are identified and no changes are necessary to any existing AMPs.

Conclusion

The staff has reviewed the licensee's assessment of the effects of the proposed EPU on DC onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the DC onsite power system will continue to meet its CLB with respect to GDC 17 as described in St. Lucie 1 FSAR Section 3.1.17 Criterion 17 - Electrical Power Systems, following implementation of the proposed EPU. Adequate physical and electrical separation exists and the system has the capacity and capability to supply power to all safety loads and other required equipment. Therefore, the staff finds the proposed EPU acceptable with respect to the DC onsite power system.

2.3.5 Station Blackout

Regulatory Evaluation

SBO refers to a complete loss of AC (LOAC) 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" (AACs). The NRC staff's review focused on the impact of the proposed

EPU 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's acceptance criteria for SBO are based on 10 CFR 50.63, guidance provided in RG 1.155 Station Blackout, and NUMARC 8700, Rev. 0. Specific review criteria are contained in SRP Sections 8.1 and Appendix B to SRP Section 8.2, and other guidance provided in Matrix 3 of RS-001.

Technical Evaluation

The licensee evaluated the impact of the proposed EPU on the plant's ability to cope with and recover from an SBO event for a period of 4 hours coping time supported by station batteries as established in the plant's licensing basis. The licensee evaluated the impacts of the proposed EPU on the following

2.3.5.1 SBO-Related Plant Functions and Programs:

SBO Coping Duration

In the LAR the licensee stated that its determination of a four-hour coping analysis was based on a probabilistic/statistical calculation which combined the probability of LOOP and loss of both EDGs, and the probabilities of not being able to restore either of these sources of AC power within 4 hours. According to the licensee, the EPU does not affect the methodology used to determine the SBO coping duration and does not affect the probability values used in the probabilistic/statistical calculation. In Attachment 5, Section 2.3.2 of the LAR the licensee evaluated EPU grid stability studies and recommends modifications to maintain necessary stability. The licensee stated in its LAR that the recommended modifications will successfully maintain required grid stability and not increase the likelihood of an SBO event. Based on the staff's review of the LAR, the staff finds that the proposed EPU does not affect the current SBO coping duration.

Condensate Inventory for Decay Heat Removal

According to the licensee, the available condensate inventory reserves for St. Lucie 2 of 307,000 gallons required per existing TS 3.7.1.3 exceeds the analyzed minimum required condensate inventory of 154,000 gallons to accommodate an SBO under EPU conditions. Based on its review of the licensee's evaluation, the staff finds that there is no change in condensate inventory for SBO due to the EPU. Therefore, the existing requirements remain bounding under EPU conditions.

Class 1E Battery Capacity

The staff reviewed the licensee's response dated October 31, 2011, and the licensee's evaluation of the effects of the EPU on the Class 1E battery capacity for the four-hour SBO coping duty cycle and finds that there is no impact on the Class 1E battery capacity and load profiles after the EPU implementation, and that SBO strategies also remain unchanged. Based on its review the staff finds that the EPU has no effect on 125 V DC Class 1E batteries.

Control Room habitability

The staff reviewed St. Lucie 2 FSAR Section 15.10.2 and the LAR for control room habitability. The staff noted that the LOAC will result in a loss of control room air conditioning. The low initial temperature of the control room and the reduced internal heat loss due to loss of power will serve to moderate the temperature rise resulting from loss of cooling. In addition, certain manual actions can be performed such as opening roof top dampers and exterior doors to established natural circulation path to help reduce the temperature rise. The source of internal heat loads in the control room during SBO is DC powered equipment and safety-related instrumentation powered from inverters. Since EPU has no effect on the 125 V DC systems, the staff finds that EPU will not have any effect on heat loads in the control room during an SBO event. Based on the above review, the staff finds that the proposed EPU will not affect the evaluation of control room habitability addressed in FSAR Section 15.10.2.

Radiological release due to EPU

The licensee's evaluation indicated that the conservatively calculated doses due to SBO are within the applicable guidelines; and therefore, will not be adversely impacted as a result of operating under EPU conditions.

EDG Reliability program

The staff reviewed the EDG Reliability program addressed in FSAR 8.3.1.1.2(m) and the licensee's evaluation in the LAR and finds that the licensee's EDG reliability program meets the guidelines of RG 1.155 Station Blackout, August 1988, Position 1.2, Reliability Program. Based on its review, the staff finds that this program is unaffected by the proposed EPU.

Modifications required in support of EPU

The staff reviewed the licensee's evaluation of the proposed modifications for the EPU and finds that the proposed modifications will not have any adverse impact on the capability to cope with an SBO event at EPU conditions.

2.3.5.2 SBO Safety Analysis

In support of its EPU application, the licensee performed an SBO thermal-hydraulic (T-H) analysis at EPU conditions for a period of 4 hours and discussed the analysis in licensing report Section 2.3.5 and the licensee's response to requests for additional information (RAIs) SRXB-40 through SRXB-43 in FPL letter L-2011-532 (Reference 11). The NRC staff has reviewed the SBO analysis and the associated RAI response, and provided the following evaluation.

Computer Code Used for the SBO Analysis

The licensee performed a T-H analysis of an SBO event for EPU conditions by using the NRC-approved RETRAN code, which was documented in WCAP-14882-P-A, "Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analysis (ADAMS Accession No. ML093421329)." The licensee analyzed the SBO event as a loss of FW with a concurrent LOOP event for a period of 4 hours. As indicated in Table 1 of the SER approving the Topical Report, WCAP-14882-P-A, the NRC previously approved the use of RETRAN for the loss of main FW event with and without LOOP. The licensee confirmed that the use of the RETRAN for the SBO analysis presented for the EPU was in compliance with the SER limitations. The analysis calculated that at the peak of voiding in the RV upper head, water level was 7 feet above the top of the RCS hot leg, and that the minimum subcooling margin at the hot leg inlets was of more than 26 °F. These results provided reasonable assurance that no steam bubbles would be carried into the hot legs, U-tubes, cold legs, downcomer and lower core regions. Since no bubbles would present in these regions, natural recirculation flow could be maintained and a reflex boiling condition would not be reached. Based on the above discussion, the NRC staff found that the RETRAN was an NRC-approved code for use in the St. Lucie 2 analysis of transients including a loss of FW with LOOP event and the licensee's use of RETRAN was within the applicable conditions of the code. Therefore, the NRC staff determined that the use of the RETRAN code for the SBO analysis was acceptable.

RCP Seal Leakage Rates

The licensee modeled in the SBO analysis a total RCS leakage rate of 16 gpm, which was consistent with that of the AOR presented in updated final safety analysis report (FSAR) Table 15.10-2. The breakdown of the total RCS leakage in Table SRXB-40-1 of FPL letter L-2011-532 (Reference 11) showed that the RCP seal leakage, resulting from a loss of seal cooling during the SBO event, was 1 gpm. In support of the assumed RCP seal leakage, the licensee referred the results of the RCP seal test in WCAP-16175-P-A (Rev. 0), "Model for Failure of RCP Seals Given Loss of Seal Cooling RCS in CE NSSS Plants." WCAP-16175-P-A was previously reviewed and approved by the NRC with the acceptance bases discussed in an SER dated February 12, 2007 (ADAMS Accession No. ML070240429). WCAP-16175-P-A contained a discussion on a loss of CCW analysis and results of the RCP seal test performed for St. Lucie by RCP vendor Byron Jackson. The RCP test considered seal exposure to water temperature of 550 °F at a pressure of 2250 psig for duration of 100 hours. The results of the tests showed that RCP seal leakage was of the order of 0.25 gpm during the 100 hours. Since the duration of the SBO analysis performed for the EPU was significantly shorter than the test documented in WCAP-16175-P-A and the RCS pressures and cold temperatures were below the test conditions of 2250 psia and 550 °F, respectively, the NRC staff agreed with the licensee that the use of a total of 1 gpm for the RCS seal leakage was appropriate and acceptable. As described in WCAP-16175-P-A, an analysis was also performed by CE, simulated an 8-hour SBO event to test the upgraded Byron Jackson N-9000 seals. This analysis simulated depressurization and repressurization in order to model a closer approximation of a typical 8-hour SBO event. The analysis was applicable to St. Lucie 2, since St. Lucie 2 was upgraded to the N-9000 seals in 1999. Test data from the CE analysis showed, on Page B-29 of WCAP-16175-P-A, that the maximum seal leakage was about 0.04 gpm. This result further supported the use of the RCP seal leakage of 1 gpm in the SBO analysis.

Plant Conditions

The licensee provided in Table SRXB-43-1 of FPL letter L-2011-532 (Reference 11) the values of key plant parameters and bases of the selection of the value for each of the following plant parameters.

1. The low RCS flow trip signal was actuated when the flow decreased to 91.9 percent of the thermal design flow. This setpoint was based on the nominal setpoint minus uncertainty. The lower trip setpoint delayed the reactor trip time and caused more energy stored in the RCS primary side, resulting in a higher RCS pressure, and therefore, it was conservative and acceptable.

2. The nominal value of 1000 psia was used for the opening setpoint for the first bank of MSSVs. The licensee confirmed that the MSSVs opening setpoint would have a negligible effect on the minimum SG inventory. In addition, the MSSVs actuated only during the first 30 minutes of the event, at which point the SG pressure was reduced via operation of the atmospheric dump valves (ADVs).

3. The AFW actuation signal was actuated when the SG water level decreased to 5 percent of the SG narrow range span (NRS). This setpoint was used to match the value used in the AOR. Also, the actuation setpoint of 5 percent SG NRS level was lower than the allowable TS setpoint of 18 percent NRS minus the uncertainty of 5 percent NRS. A lower actuation setpoint delayed the AFW injection into the SG and delayed heat removal from the RCS, and thus, was conservative, resulting in a higher peak RCS pressure.

4. The AFW flow injection to the SGs was delayed by 300 seconds following the AFW actuation signal. This delay time was greater than that based on IST acceptance criteria. A longer AFW flow delay time maximized energy to be removed from the RCS for the event, and was conservative, resulting in a higher peak RCS pressure.

5. The total AFW flow was assumed to be 500 gpm which was based on the total flow rate of the turbine driven AFW pump as both electrical driven pumps were assumed to be inoperable during the SBO event.

6. The operator opened ADVs to control SG pressure when the SG pressure reached to 900 psia. Operator action of opening the ADVs was credited at 30 minutes into the event to maintain cooling in the RCS. The assumption was acceptable, because an opening pressure of 900 psia was chosen to be consistent with the AOR to mimic steam relief typically provided by the steam bypass control system when normal or offsite power was available.

7. The MSSVs were assumed to close when the SG pressure decreased to 995 psia. This setpoint was based on the opening setpoint minus 5 psia. This assumption was consistent with Westinghouse standard methodology used for similar events with small RCS blowdown rates.

Based on the above discussion, the NRC staff determined that the assumed plant conditions were adequate, resulting in a high heat load to be removed from the RCS, and therefore, the assumptions were acceptable.

No single failures were considered in the SBO analysis at EPU conditions. This assumption was consistent with 10 CFR 50.2, “Definitions,” which did not require consideration of a single failure in an SBO analysis.

Instrumentation and Equipment Used for SBO Mitigation

In the response to RAI SRXB-43 (Reference 11), the licensee listed the instrumentation required to remain functional during an SBO. The instrumentation included (1) pressurizer pressure indicator, (2) SG pressure indicator, (3) SG water level indicator, (4) engineered safety features actuation system (ESFAS), (5) AFW actuation system, (6) reactor protective system (including hot and cold leg temperature, neutron flux), (7) AFW valve position indicator, and (8) power-operated-relief-valve (PORV) position indicator. The licensee stated that the instrumentation listed above were safety grade except for the AFW valve and PORV position indicators. Since pressurizer pressures did not reach the PORV opening setpoint, the PORV position indicator, a non-safety-grade instrument, was not credited in the T-H analysis performed for EPU during a SBO event. The licensee indicated that although the AFW valve position indicator was not safety grade, AFW flow could be confirmed through using the safety grade SG level indication instrumentation.

Also, the licensee listed the following equipment required to remain functional in an SBO: (1) CEDM; (2) condensate storage tank; (3) AFW pump 2C; (4) steam supply to AFW turbine driven pump isolation valves; (5) AFW flow control valves; (6) ADVs; (7) AFW isolation valves; (8) MSSVs; (9) letdown isolation valves; and (10) turbine stop valves. The licensee stated that the equipment listed above were safety grade except for the turbine stop valves. Closure of the turbine stop valves was credited in the SBO analysis. This assumption was conservative, because early isolation of the steam to the turbine would place a greater strain on the AFW system, and thus condensate inventory in removing decay heat from the RCS. The licensee indicated that the design of the turbine stop valves would ensure the valves in the closure position when failed. Also, the stop valves were backed up by the closure of the turbine governor valves. Therefore, a failure of turbine stop valves would still result in steam isolation to the turbine and would not affect the results of the SBO analysis. In addition, the safety grade MSIVs would be fully closed approximately 3 seconds after turbine trip.

Since (1) a majority of the instrumentation and equipment required remaining functional were safety grade, (2) back-up systems were available for the non-safety grade systems, the NRC staff determined that the required instrumentation and equipment were reliable for use in mitigating the consequences of an SBO event, and therefore, they were acceptable.

Results of the SBO Analysis

The results of the analysis, presented in Table 2.3.5-1 and Figure 2.3.5.1 through Figure 2.3.5-9, showed that (1) the peak RCS was 2389 psia, (2) the minimum hot leg subcooling margin was 26.1 $^{\circ}$F, (3) the condensate inventory reserved for St. Lucie 2 was available to accommodate an SBO under EPU conditions, and (4) natural circulation and core cooling could be maintained for 4-hour duration.

Based on its review discussed above, the NRC staff found that (1) the analysis used an NRC-approved code, (2) the instrument and equipment credited for consequence mitigation were reliable, (3) the assumed plant conditions were adequate, resulting in a higher heat load to be removed from the RCS, and (4) the results showed that core coolability could be maintained for a 4-hour period during an SBO event, meeting the requirement of Paragraph (a)(2) of 10 CFR 50.63. Therefore, the NRC staff determined that the SBO analysis was acceptable.

2.3.5.3 Impact on License Renewal

In the LAR, the licensee stated that the systems required to mitigate the SBO event are within the scope of license renewal. The licensee evaluated operation of the systems required to mitigate the SBO event under EPU conditions to determine if there are any new aging effects requiring management or if any existing AMPs are affected. The EPU does not result in the addition of any new or previously unevaluated materials to the system nor does it result in exceeding any operating or environmental parameters previously evaluated for components included within the scope of license renewal. Thus, no new aging effects requiring management are identified and no changes are necessary to any existing AMPs.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of 4 hours established in the plant's licensing basis. The NRC staff concludes that the licensee has adequately evaluated the effects of the proposed EPU on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63, the guidance provided in RG 1.155, and NUMARC 8700, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to SBO.

2.4 Instrumentation and Controls

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

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 ESF systems and essential auxiliary supporting systems, and (4) for use to achieve and maintain a safe shutdown condition of the plant. Diverse I&C systems and equipment are provided for the express purpose of protecting against potential common-mode failures of I&C protection systems. The NRC staff conducted a review of the reactor trip system, ESFAS, safe shutdown systems, control systems, and diverse I&C systems for the proposed EPU to ensure that the systems and any changes necessary for the proposed EPU are adequately designed such that the systems continue to meet their safety functions. The NRC staff's review was also conducted to ensure that failures of the systems do not affect safety functions. The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and GDC 1, 4, 13, 19, 20, 21, 22, 23, and 24. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

Technical Evaluation

Instrument Setpoint Methodology

Per the licensee, there are two calculations pertaining to the establishment and maintenance of each TS setpoint value, an instrument uncertainty calculation and a setpoint calculation.

The instrument uncertainty calculation exists for each safety system input parameter. These calculations determine the various elements of uncertainty applicable to each component within that instrument channel from the sensor/transmitter up to the protection system cabinet input. These calculations for the SG level setpoints have been prepared by FPL in accordance with FPL standards. FPL states that this instrument uncertainty calculation standard (not submitted as part of the licensing amendment) is based on Instrument Society of America (ISA) document 67.04, Setpoints for Nuclear Safety Related Instrumentation, and NRC RG 1.105, Instrument Setpoints for Safety Related Systems (ADAMS Accession No. ML11242A148). Elements of uncertainty for individual components, such as setting tolerance, measuring & test equipment (M&TE), and drift are specifically based on associated surveillance procedure requirements and test frequencies. Environmental effects for both normal and harsh conditions are determined for each loop component as applicable. The loop setpoint calculation combines the instrument accuracy with the rack accuracy terms and establishes the setpoint for the loop. For SG level setpoints this calculation has been prepared by Westinghouse.

The full range of uncertainty effects are considered including instrument performance specifications, calibration effects, environmental effects, process effects and electrical circuit effects. Manufacturer's specification sheets and qualification reports are used as the basis for determining applicable instrument uncertainty effects, magnitudes and statistical confidence, and the extent to which each effect is random and independent. Calibration uncertainty effects, such as setting tolerance and M&TE are specifically based on associated surveillance procedure requirements. Environmental effects for both normal and harsh conditions are determined for each loop component as applicable. The maximum variation range of each applicable environmental parameter is based on the limiting analysis for which that protection function is credited.

The random uncertainty terms were based on 2σ values (ADAMS Accession No. ML11242A0149). The licensee stated that the uncertainties came from manufacturer inputs and the industry practice is to operate with the assumption of 2 σ values unless the specifications state it otherwise or knowledge base exists to the contrary. These terms were combined without scaling to calculate the total loop uncertainty (TLU). Uncertainty effects that are determined to be random and independent are combined using square root of the sum of the squares method. All other non-random/non-independent uncertainty effects are algebraically included as bias terms. No credit is taken for bias terms that are conservative with respect to the protection function. Total loop uncertainty is determined as the square root of the sum of squares of random terms plus any non-conservative bias terms. The overall calculation method is acceptable to staff based on the guidance contained in RG 1.105.

The licensee stated that it maintains a separate document for the safety analysis plant parameters (SAPP) (ADAMS Accession No. ML11242A149). The SAPP serves as a bridge between the instrument channel setpoint calculations and the safety analysis. The bounding uncertainty allowance applicable to each protection system function is documented and managed in the SAPP. Where applicable, the SAPP includes individual bounding uncertainty allowances for both normal and harsh conditions.

The non-rack component uncertainties (from the corresponding instrument uncertainty calculations) are combined with the protection system cabinet uncertainties to determine an overall TLU. These setpoint calculations also verify that the uncertainty allowances defined in the SAPP are bounding. Further, these setpoint calculations determine operability limits (OL) for the related actuation functions.

The instrument setpoints are based on using random and bias errors commensurate with the guidance contained in RG 1.105. Process errors have been considered and included when non-negligible or non-conservative. Margin is provided between the calculated error and the analyzed setpoint value. Appropriate controls are provided to maintain the variables within prescribed limits per GDC 13 and RG 1.105. The staff has determined that the setpoint method described in the licensing request meets GDC 13 and the regulatory guidance in RG 1.105.

Compliance with RIS 2006-17

Conformance with the key issues in RIS 2006-17 is summarized in the following paragraphs:

RIS 2006-17 clarified the application of the setting tolerances and the need to assure that as-left tolerance (ALT) and the as-found tolerance (AFT) is controlled such that the analyzed limits are not violated. NRC clarifications provided in RIS 2006-17 stipulate that as-left setting tolerance should be explicitly accounted for in the setpoint determination. More specifically, since the walk-away equipment setpoint may be left anywhere within the as-left band, this allowed setting tolerance should be treated as a bias in the setpoint determination. RIS 2006-17 further stipulates that the surveillance procedures should ensure that the trip setpoint is restored to within the as-left band before the channel is returned to service. To comply with this NRC guidance, the verification that the SAPP-defined uncertainty allowance is bounding (as discussed above) and has been structured to ensure that TLU plus setting tolerance (ST) is less than or equal to SAPP allowance. To clarify, the ST is algebraically added to TLU (for SAPP allowance verification) and is also included as a random/independent term in the root-sum-square TLU calculation. In addition, St. Lucie protection system surveillance procedures require that trip setpoints are restored to within the as-left band before the channel is returned to service. Using this methodology, the SAPP uncertainty allowances are verified to be bounding for protection system functions at EPU conditions. The safety analysis Analytical Limits are based on the algebraic combination of the TS setpoint and the SAPP uncertainty allowance to ascertain that all TS setpoints are sufficiently conservative at EPU conditions to ensure that applicable safety limits will not be exceeded if a design basis event occurs before the next periodic surveillance.

Additional NRC guidance provided in RIS 2006-17 stipulates use of an as-found acceptance criteria band centered about the field trip setpoint or FTSP (FTSP is same as nominal trip setpoint or NTSP as used in RIS 2006-17) as a measure of instrument channel operability. To comply with this NRC guidance, the setpoint calculations have been structured to include determination of an operability limit (OL) band. For St. Lucie, the OL band is synonymous with the as-found acceptance criteria band. The operability determination for St. Lucie 1 protection system monthly functional surveillance tests is explained in revised Notes 8 and 9 of Table 4.3-1, Reactor Protective Instrumentation Surveillance Requirements of the TSs as stated later in this section (Reference 12).

Historically, St. Lucie has used an as-found tolerance band width equal to 2 times the procedure ST as the basis for initiation of corrective action under the CAP program. This ST used for periodic surveillance is for the rack accuracy components. This ST value is ±0.25 percent for St. Lucie 2. The stated as-found tolerance band width meets the intent of the NRC guidance since the previous as-left setting may be anywhere within one ST band width, leaving just one ST band width for accommodation of drift and other periodic test uncertainties. As-found readings within the allowed ST are not typically optimized in the monthly functional surveillance procedures. Therefore, the as-left setting tolerance is treated as a bias. The licensee considered other methodologies for calculation of an OL band width based on a statistical combination of drift and other periodic test uncertainty effects, but rejected them since the resultant OL bands were either larger or smaller than reasonable. Therefore, the OL band (synonymous with the as-found acceptance criteria) is based on 2 times the ST and is normally centered about the nominal equipment setting (clarified as the field trip setpoint or nominal trip setpoint). It should be noted that for St. Lucie 2, the OL band is synonymous with the as-found acceptance criteria and is normally centered about the nominal equipment setting (clarified as the field trip setpoint or nominal trip setpoint). In its originally submitted application, FPL proposed to use unequal setting tolerances (ALT and AFT) around the FTSP, which was not acceptable to the staff as there was insufficient justification for using unequal tolerances around the FTSP. Staff maintained that the instrument deviations are treated as random (Gaussian) distribution and hence must be centered around the FTSP. In their November 2, 2011, response to the staff request (ADAMS Accession No. ML11308B350) for further clarifications, the licensee agreed to use equal setting tolerances around the FTSP.

The licensee has proposed to add the following two notes to TS Table 4.3-1, Reactor Protective Instrumentation Surveillance Requirements pertaining to Functional Unit 7, Steam Generator Water Level –Low under Channel Functional Test with frequency M (monthly):

> (8) - If the as-found channel setpoint is either outside its predefined as-found acceptance criteria band or is not conservative with respect to the Allowable Value, then the channel shall be declared inoperable and shall be evaluated to verify that it is functioning as required before returning the channel to service.
>
> (9) - The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Field Trip Setpoint, otherwise that channel shall not be returned to OPERABLE status. The Field Trip Setpoint and the methodology used to determine the Field Trip Setpoint, the as-found acceptance criteria band, and the as-left acceptance criteria are specified in the FSAR Section 7.2.

The ALT is considered both as a random and a bias term and this is a conservative assumption per the clarifications in RIS 2006-17. The ALT and the AFT tolerances are acceptable and are centered around the NTSP (FTSP). The notes clarify the actions required if the ALT or the AFT is found to exceed the specified tolerances. Therefore, the staff has determined that the application of the clarifications of RG 1.105 in RIS 2006-17 are acceptable.

Summary of Low SG Level Setpoint/Uncertainty Calculations

This summary uses the following terms and acronyms:

A	Device reference accuracy
C	Calibration tolerance (where used combines ST and M&TE)
D	Drift
FTSP	Field trip setpoint
LT	Level transmitter
LY	Level channel signal converter (I/E signal converter)
LY-1	Level channel signal converter (E/I signal converter)
M	Measuring and test equipment (M&TE)
OL+	Upper operability limit
OL-	Lower operability limit
PS	Power Supply
R	Radiation effects (Ra and Rn for accident and normal)
REP	Repeatability
RLE	Reference leg effect (RLEa and RLEn for accident and normal)
S	Seismic Effect
SAPP	Safety analysis plant parameters

SPE	Static pressure effect
SQRT	Square root
ST	Setting tolerance
T	Temperature Effect (Ta and Tn for accident and normal)
TLU	Total loop uncertainty (TLUa and TLUn for accident and normal)
UA	Uncertainty Allowance

For the RPS Low SG Level trip function, the channel consists of a Rosemount Model 1154DP transmitter, a Foxboro model 2AI-I2V I/E signal converter, a Foxboro model 2AO-V2I E/I signal converter and the Electro Mechanics model 34860 RPS bistable trip unit. Device uncertainties that were determined to be both applicable and non-negligible are summarized in the table below. Other effects, including dynamic effects, were also evaluated.

Several process effects, specifically the downcomer velocity effect, the void fraction effect, etc., have not been included in the low SG level protection functions since they produce conservative biases.

The reference leg effect analysis incorporates both the hydrostatic pressure and FW subcooling effects and they have been included in the TLU for the normal as well as the accident case conditions because they produce non-conservative biases.

The magnitude of the non-conservative acceleration effect through the SG frustum (frustum) is small in relation to the conservative downcomer velocity effect. Since FP&L does not credit the downcomer velocity term, the acceleration effect does not have to be included in the RLE error calculation.

Effects other than those specifically addressed above are either very small or conservative and have not been included in the calculations.

The licensee did not include seismic uncertainties initially in the calculations because for earthquakes greater than the operating basis earthquake (OBE) the plant is required to be shutdown for evaluation. For small confirmed earthquakes below OBE all instrument loops are monitored to check the drift due to seismic event. The staff sought clarification because the equipment may have to perform its safety function subsequent to an earthquake and prior to checking out the calibration drift and the need for recalibration. In the January 14, 2012, response (ADAMS Accession No. ML12019A076), the licensee included the error due to seismic events and revised the setpoint calculation to include the seismic error component.

Radiation effects under normal conditions were neither included nor an explanation provided as to why they have not been included. Staff requested a clarification for not addressing the radiation effects under normal conditions. In its January 14, 2012, response (ADAMS Accession No. ML12019A067), the licensee explained that the radiation dose under normal conditions is very low. The level transmitters are located outside the bioshield wall and the normal dose without fuel failure for 22.5 months is less than 250 Rads for 22.5 months, this represents a mild environment and any minor calibration errors are calibrated out during refueling outage (every 18 months). With 1-percent fuel failure rate the 22.5 month radiation dose is less than 1410 Rads. This radiation dose does not represent a harsh environment for the Rosemount 1154DP transmitter and hence not accounted for in the calculation. The level transmitters are qualified to an integrated dose of over 10 E^6 (10×10^6). Equipment other than the level transmitters is located in the control room which is a mild environment (integrated 60 year dose rate less than 300 Rads). Based on this explanation the Staff finds the rationale for not including radiation error under normal conditions is acceptable.

Per the licensee, insulation resistance (IR) effects are not included in the RPS low level trip function because no credit is taken for this function for actuation under long term accident conditions. Therefore, the IR error due to high radiation for normal and accident conditions is negligible (Reference 13).

RPS Low SG Level Instrument Loop Device Uncertainties

	(LT)	**(LY)**	**(LY_1)**
Reference accuracy (A)	±0.25% span	±0.25% span	±0.50% span
Calibration Tolerance (C)	±0.43% span	±0.43% span	±0.87% span
Drift (D)	±0.32% span	±0.25% span	±0.50% span
Power Supply	NA	±0.20% span	±0.50% span
Seismic Effect	±0.40% span	NA	NA
Temperature effect Normal (Tn) Accident (Ta)	 ±0.70% span ±4.20% span	 ±0.12% span	 ±0.12% span
Repeatability (REP)	NA	NA	±0.10% span
Static Pr. Effect (SPE)	±0.45% span	NA	NA
Radiation Eff Acc (Ra)	±1.61% span	NA	NA
Insul Res Acc only (IR)	±0.25% span	NA	NA
Reference leg effect Normal (RLEn) Accident (RLEa)	 +0.86% span +7.94% span	 NA NA	 NA NA

RPS Bistable Trip Unit Uncertainties

Accuracy (A)	±0.08% span
Setting Tolerance (ST)	±0.25% span
M&TE error (M)	±0.08% span
Drift (D)	±0.05% span
Seismic Effect (S)	±0.13% span
Temperature effect (Tn)	±0.23% span
Test Trip PS (TPS)	-0.01% span

Total Loop Uncertainty Calculations and SAPP Uncertainty Allowance Verification

The Total Loop Uncertainty (TLUn) with normal environmental conditions for the RPS Low SG Level trip function is calculated as follows:

$$TLUn = SQRT(A\_LT^2 + A\_LY^2 + A\_LY\_1^2 + A\_BTU^2 + C\_LT^2 + C\_LY^2 + C\_LY\_1^2 + ST\_BTU^2 + M\_BTU^2 + D\_LT^2 + D\_LY^2 + D\_LY\_1^2 + D\_BTU^2 + PS\_LY^2 + PS\_LY\_1^2 + Tn\_LT^2 + Tn\_LY^2 + Tn\_LY\_1^2 + Tn\_BTU^2 + REP\_LY\_1^2 + SPE\_LT^2 + S\_LT^2) + RLEn\_LT + S\_BTU$$

TLUn = 1.80 + 0.86 + 0.13% span = 2.79% span
TLUn + ST = 2.79+0.25% span = 3.04% span
SAPP normal uncertainty allowance = 5% span
Net margin for normal case is 1.96% (5.0%-3.04%)

Note: 1. S_BTU is considered as a bias term.
2. The negative trip test power supply error of -0.01% span is ignored for conservatism

The Total Loop Uncertainty (TLUa) with accident environmental conditions for the RPS Low SG Level trip function is calculated as follows:

TLUa = SQRT(A_L T^2 +A_LY^2 +A_LY_1^2 +A_BTU^2 + C_L T^2 + C_LY^2 + C_LY_1^2 + ST_BTU^2 + M_BTU^2 + D_LT^2 + D_LY^2'+ D_LY _1^2 + D_BTU^2 + PS_LY^2 + PS_LY_1^2 + Ta_L T^2 + Tn_LY^2 + Tn_LY_1^2 + Tn_BTU^2 +REP_LY_1^2 + SPE_L T^2 + Ra_LT^2 _) + RLEa_LT + S_BTU
TLUa = 4.79+7.94 +0.13% span = 12.86% span
TLUa + ST = 12.86 + 0.25% span = 13.11% span
SAPP accident uncertainty allowance = 14% span
Net margin for accident conditions is 0.89% (14.0%-13.11%)

Operability Limit Calculations
RPS Low S/G Level bistable trip unit Signal Range = -1 volts DC (Vdc) to -5 Vdc for 0% to 100%
RPS Low S/G Level bistable trip unit FTSP = -2.420 Vdc or 35.5% span

RPS Low S/G Level bistable trip unit ST Range = -2.410 Vdc to -2.430 Vdc
RPS Low S/G Level bistable trip unit ST Band Width = 20 millivolts (mV)
RPS Low S/G Level bistable trip unit OL+ = -2.440 Vdc or 36.00% span
RPS Low S/G Level bistable trip unit OL- = -2.400 Vdc or 35.00% span
RPS Low S/G Level bistable trip unit OL Range = -2.400 Vdc to -2.440 Vdc
RPS Low S/G Level bistable trip unit OL Band Width = 40 mV

The calculated setpoints conform to the guidance of RG 1.105 and RIS 2006-17 and have sufficient margin between the calculated value and the analyzed value to provide reasonable assurance that the analytical limits will not be exceeded and that the instruments will be operable.

Therefore, the staff has determined that the proposed changes meet the TS requirements of 10 CFR 50.36 and the guidance in RG 1.105.

TSs changes related to the power uprate

The following TS changes have been proposed by the licensee:

TS Table 2.2.1, Functional Unit 6, Steam Generator Pressure – Low

The licensee has proposed to change the Trip Setpoint and the Allowable values from ≥ 626.0 psia (2) to ≥ 626.0 psia$^{(2)}$. This change is purely administrative in nature and is acceptable to Staff.

TS Table 2.2-1, Functional Unit 8, Steam Generator Water Level - Low

The licensee has proposed to increase the trip setpoint for SG water low setpoint from ≥ 20.5 percent water level – each SG to ≥ 35.0 percent water level – each SG. In addition, the licensee has proposed to change the corresponding allowable values from ≥ 19.5 percent to ≥ 35.00 percent.

In support of this change the licensee has proposed to add the following two notes:

> If the as-found channel setpoint is either outside its predefined as-found acceptance criteria band or is not conservative with respect to the Allowable Value, then the channel shall be declared inoperable and shall be evaluated to verify that it is functioning as required before returning the channel to service.
>
> The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Trip Setpoint, otherwise the channel shall not be returned to Operable status. The Trip Setpoint and the methodology used to determine the Trip Setpoint, the as-found acceptance criteria band, and the as-left acceptance criteria are specified in the FSAR Section 7.2.

The license has determined that with the EPU, the accident and transient analysis results show that the existing setpoint of ≥ 20.5 percent water level with all RCPs operating is satisfactory. The licensee has stated that the revised trip setpoint of ≥ 35.0 percent water level provides for greater operator response time for restoration of FW following a total loss of FW event, thereby resulting in an overall risk reduction. Based on the accident and transient analysis and the greater operator response time, the staff has determined that the rationale for changing this setpoint is acceptable.

The second note regarding the as-left channel setpoint is acceptable as it ensures that the as-left tolerance will be within the as-left setting allowance.

Table 2.2-1, Functional Unit 14, Reactor Coolant Flow - Low, in the Trip Setpoint column and the Allowable value column have been changed from "≥ 95.4 percent of design Reactor Coolant flow with four pumps operating*" to "≥ 95.4 percent of minimum Reactor Coolant flow with four pumps operating*,"

The note indicated by * has been changed from, "Design reactor coolant flow with 4 pumps operating is the minimum RCS flow specified in the COLR [core operating limits report] Table 3.2.2" to, "For minimum reactor coolant flow with 4 pumps operating, refer to TS LCO [limiting condition for operation] 3.2.5."

One of the inputs and assumptions used in the calculation of the NSSS design parameters established an increased minimum RCS total flow requirement of 375,000 gpm to ensure that the reactor core thermal margin safety limit is not exceeded. In letter L-2011-422, dated October 10, 2011 (ADAMS Accession No. ML11285A047), FPL clarified that LCO 3.2.5 will be revised from "c. Reactor Coolant System Total Flow Rate" to "c. Reactor Coolant System Total Flow Rate – greater than or equal to 375,00 gpm..." This change is consistent with the new analyzed reactor coolant flow rate needed to support EPU conditions.

TS Table 4.3-1, Reactor Protective Instrumentation Surveillance Requirements, Function 8, SG Water Level - Low

The licensee has proposed to add Notes 8 and 9 (as enumerated in Section 1.0 of this SE) to meet the guidance of RG 1.105 and the clarifications provided in RIS 2006-17. As noted in Section 3.3.2 above, Notes 8 and 9 meet the staff guidance and are acceptable.

Control Systems

The following changes are related to control systems. The purpose of review is to evaluate that there will be no adverse affect on safety due to these changes.

Turbine first stage pressure instrumentation

Turbine first stage pressure increases essentially linearly from 0 percent–100 percent turbine load when the turbine generator is on line and it provides a close correlation of secondary power to reactor power. This allows turbine first stage pressure to be used as a reliable input demand signal or permissive to the various reactor control systems between 0 percent and 100 percent reactor power. The current 0 percent - 100 percent turbine load turbine first stage pressure correlates to 0 – 515.4 psig. The current high pressure (HP) turbine has a governing stage and the governing stage exit pressure (impulse pressure) is used as the reference value for the first stage pressure. For EPU, a new HP turbine is being installed, which does not have a governing stage. Therefore, the first stage pressure is the HP control valve exit pressure. The new HP turbine currently is expected to generate a 0 to 100 percent power corresponding to a nominal first stage turbine pressure of 0 to 788.6 psig. This significant increase in first stage pressure is because of no governing stage in the new HP turbine. Actual full power turbine first stage pressure may change slightly as the HP turbine design is refined and instrument calibrations will be revised accordingly. The change in the first stage pressure is needed due to change in the HP turbine design. For EPU conditions the analyzed main steam design pressure is 985 psig remains unchanged and the pressure at the common header to HP turbine throttle valves for EPU conditions is 866.5 psia compared with the current value of 861.9 psia (Reference 2). The main steam design pressure setting envelopes the new turbine first stage throttle pressure and therefore, this change does not adversely affect any safety system.

Reactor Regulating System

The reactor regulating system responds to changes in RCS temperature and secondary load as sensed by the RCS measured T_{avg} (average temperature) instrumentation and turbine first stage pressure instrumentation. The reactor regulating system is designed to calculate the 0 to 100 percent T_{avg} program reference value (T_{ref}) (reference temperature) derived from 0-100 percent power turbine first stage pressure. The reactor regulating system calculates the pressurizer water level setpoint based upon T_{avg}. In addition, the reactor regulating system provides deviation alarms for (T_{avg} - T_{ref}).

For EPU, the T_{ref} temperature program must be rescaled such that the new 0 to 100 percent power turbine first stage pressure range of 0 to 788.6 psig corresponds to the new T_{avg} range of 532 – 577.3 °F (Reference 2). For EPU, the low limit T_{avg} setpoint is at 15 percent power for T_{avg} of 538.7 °F. The high limit T_{avg} setpoint is at 90 percent power for T_{avg} of 572.3 °F. For measured T_{avg} below 15 percent load, the level program is the same as at 15 percent power and for the measured T_{avg} above the 90 percent load, the level program is the same as the T_{avg} at 90 percent power. The current T_{ref} varies linearly with power from a nominal temperature of 532 ºF at a hot standby condition to 573.3 ºF at 100 percent power. Even though the T_{ref} program has been changed, the pressurizer design does not change because it was originally designed for a design pressure of 2485 psig at a design temperature of 700 °F. EPU conditions do not exceed these parameters. There is no safety function associated with this change. Based on the foregoing discussion, the changes in the scaling for the reactor regulating system are needed due to change in the turbine first stage pressure (described above) and do not adversely affect operation of any safety system.

Pressurizer Level Control System

The pressurizer level control system maintains the pressurizer level within a programmed band consistent with measured T_{avg}. The programmed level is designed to maintain a sufficient margin above the low level alarm where the heaters turn off while maintaining the level low enough that a sufficient steam volume is maintained to ensure the pressurizer does not go solid during accidents and transient conditions. Since full power T_{avg} temperature has changed for EPU, the nominal pressurizer level program temperatures for the low and high level limits have changed for EPU. The low limit T_{avg} setpoint is at 15 percent power temperature of T_{avg} 538.7 °F. The high limit T_{avg} setpoint is at 90 percent power corresponding to a T_{avg} temperature of 572.3 °F. The level control program is linear between 15 percent power T_{avg} and the high limit T_{avg}. For measured T_{avg} below 15 percent load, the level program is constant at the low limit. For measured T_{avg} above the high limit T_{avg} setpoint, the level program is constant at the high limit. Since the low and the high level limits have not changed due to EPU, the changes in the pressurizer level control needed for EPU do not adversely affect any safety system.

FW Regulating System

The FW regulating system, which is a subsystem of the distributed control system (DCS), maintains SG water level within acceptable limits by positioning the main FW regulating valves and FW bypass valves. In addition, in the event of a reactor trip or turbine trip, the FW regulating valves are closed and the DCS controls SG level via the FW bypass valves. For EPU, the FW regulating valves are being modified. Therefore, changes to the FW regulating and FW bypass valve demand programs within the DCS software are required. In addition, changes were made to the post trip (turbine trip override) control setpoints to improve level response following a reactor trip. FW isolation is required for a variety of postulated transients and accident events. The current plant design provides for FW isolation using the redundant safety related FW isolation valves. The main FW isolation valves (MFIVs) have been evaluated for the increased flow rates, DPs, and temperatures at EPU. Isolation of these valves is classified as a safety function. The licensee confirms that the MFIVs and FW isolation valves will continue to meet the existing required valve closure response times at the EPU conditions (Reference 2). Containment isolation is accomplished by the provision of the redundant MFIVs on the FW headers outside containment. The containment isolation requirements are unaffected by EPU and the current plant design features remain acceptable.

The safety function of FW isolation is not affected by EPU and other changes to the non-safety part of the control systems do not affect plant safety. Therefore the changes described above do not adversely affect safety systems.

Steam Bypass Control System (SBCS)

The SBCS is comprised of five valves, one bypass valve and four dump valves, which dump steam to the condenser. For EPU, the capacity of the steam dump and bypass valves is being increased. Therefore, changes to the valve demand programs within the SBCS control logic are required. In addition, the response time and the setpoint for the large load rejection permissive signal was reduced, which allows the system to respond in a valve quick open mode of operation (rather than valve modulation mode) to improve the overall transient response. Minor changes are being made to the master valve controller output signal tracking logic to provide a smoother transition back to steam pressure modulation control following an initial SBCS quick open response to a large load rejection event.

The current SBCS load rejection capacity of 29 percent remains unchanged. However, to maintain the load rejection capability at higher steam flow the SBCS flow capacity will be increased and valve response time decreased to maintain operating margin under EPU conditions, and to decrease challenges to the RPS by increasing the size of the step load reduction that can be mitigated by the control systems without a reactor trip. The analysis used increased SBCS valve capacities with linear trim and a two second quick open stroke time due to the EPU (ADAMS Accession No. ML110730299).

Based on the increased steam bypass capability to handle loss of load at the 29 percent capacity, the probability of challenges to the RPS remains unchanged. There is no safety function for this system and the proposed changes do not adversely affect safety systems.

Moisture Separator Reheater (MSR) and FW Heaters 5A/B Level Controls

The existing pneumatic controls for MSR and high pressure FW heater 5 level control are being replaced with electronic instruments. The existing backup level switch control functions will not be changing. This change in the non-safety system does not adversely affect the safety systems.

Condensate and FW System

The following modifications will be made to the condensate and FW system to regain operating margin when the power uprate occurs on the main FW system:

- The condensate and the FW pumps will be replaced to meet the increased flow demand.
- FW Pump Suction – Low suction pressure alarm and pump trip setpoints will be revised as necessary to reflect EPU operating conditions and requirements for the replacement main FW pumps.
- FW Flow – The range of the various FW flow channels will be increased to accommodate the higher EPU flow rates. Those instrument channels with an upper range of 7E6 lbm/hr will be revised for an expanded upper range of 8E6 ($8x10^6$) lbm/hr. All associated indicators, recorders, computer points, and alarm setpoints will be rescaled as necessary.

There is no safety function associated with these changes. These controls changes are needed for EPU and they do not adversely affect the safety systems.

Main Steam System

The range of the various main steam flow channels will be increased to accommodate the higher EPU flow rates. Those instrument channels with an upper range of 7E6 lbm/hr will be revised and rescaled for an expanded upper range of 8E6 lbm/hr. All associated indicators, recorders, computer points, and alarm setpoints will be rescaled as necessary.

Due to EPU conditions, the main steam flow rate from each SG will increase from the normal operation pre-EPU total flow rate of approximately 5,903,370 lbm/hr to a post-EPU total normal flow rate of approximately 6,663,100 lbm/hr. Due to this increase in main steam flow rate, the capability of the MSIVs required evaluation, which confirmed satisfactory EPU performance, including the ability to meet the safety-related isolation function to prevent uncontrolled blowdown of both SGs in the event of a steam line rupture accident (ADAMS Accession No. ML110730299).

These controls changes are needed for EPU and they do not adversely affect the safety systems.

Turbine Cooling Water System

EPU evaluation has resulted in the following modifications:

- Replacement of isolated phase bus air coolers flow indicator,
- Replacement of turbine generator outboard and inboard exciter coolers, and
- Replacement of generator hydrogen coolers.

There is no safety function related to these changes and they do not adversely affect the safety systems.

Turbine Generator Control

As part of EPU, a new HP turbine rotor is being installed. With the new turbine, the control valve program will be changed from partial arc emission admission control (load change controlled by sequential valve opening) to full arc emission admission control (load change controlled by all valves moving together). Additionally, a new digital turbine control system (TCS) is being installed resulting in the modification to the existing turbine controls and the turbine overspeed protection system. This change will also include new control room displays and controls to provide operator interfaces with the digital TCS.

A reactor trip is initiated on a turbine trip. The signal for this trip comes from four hydraulic oil pressure switches and is not dependent on the digital control system. In addition, a turbine trip event is bounded by the loss of external load event. Thus this change will not result in an adverse affect to the safety systems.

The control system changes described above are needed to support the EPU implementation due to larger flows, greater pressure, etc. Since these changes pertain to non-safety systems and do not adversely affect the systems, they are acceptable to staff.

Conclusion

The NRC staff has reviewed the licensee's application related to the effects of the proposed EPU on the functional design of the reactor trip system, ESFAS, safe shutdown system, and control systems. The licensee has described (Section 2.4 of the licensing report (Reference 2)) how the proposed changes continue to meet the requirements of 10 CFR 50.55a(a)1, 10 CFR

50.55(a)(h), 10 CFR 50.36(c)(1)(ii)(a), and GDC 1, 4, 13, 19, 20, 21, 22, 23, and 24. After review, the NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on the I&C portion of these systems and that the changes that are necessary to achieve the proposed EPU 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), 10 CFR 50.36(c)(1)(ii)(a) and the updated FSAR section 3.1 (that explains how the design bases are measured against the current GDC as amended through February 1971) for meeting GDC 1, 4, 13, 19, 20, 21, 22, 23, and 24. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to I&C.

2.4.2 Measurement Uncertainty Recapture

Regulatory Evaluation

Nuclear power plants are licensed to operate at a specified core thermal power. Appendix K, "ECCS Evaluation Models," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," requires LOCA and ECCS analyses to assume "that the reactor has been operating continuously at a power level at least 102 percent of the licensed thermal power level to allow for instrumentation uncertainties." Alternatively, Appendix K allows such analyses to assume a value lower than the specified 102 percent, but not less than the licensed thermal power level, "provided the proposed alternative value has been demonstrated to account for uncertainties due to power level instrumentation error." This allowance gives licensees the option of justifying a power uprate with reduced margin between the licensed power level and the power level assumed in the ECCS analysis by using more accurate instrumentation to calculate the reactor thermal power.

Because the maximum power level of a nuclear plant is a licensed limit, the NRC must review and approve a proposal to raise the licensed power level under the license amendment process. The LAR should include a justification for the reduced power measurement uncertainty to support the proposed power uprate.

Topical Report ER-80P and its supplement, Topical Report ER-157P, describe the Caldon LEFM (Leading Edge Flow Meter) CheckPlus™ System for the measurement of FW flow and provide a generic basis for the proposed uprate. The staff also considered the guidance of RIS 2002-03 (Reference 14), in its review of the licensee's submittals for the proposed power uprate request. By following the regulatory summary guidance provided in RIS 2002-03, the requirements of 10 CFR Part 50, Appendix K are satisfied.

Technical Evaluation

Neutron flux instrumentation is calibrated to the core thermal power, which is determined by an automatic or manual calculation of the energy balance around the plant NSSS. The accuracy of this calculation depends primarily on the accuracy of FW flow and FW net enthalpy measurements. FW flow is the most significant contributor to the core thermal power uncertainty. A more accurate measurement of this parameter will result in a more accurate determination of core thermal power.

FW flow rate is typically measured using a venturi. This device generates a DP proportional to the FW velocity in the pipe. Because of the need to improve flow instrumentation measurement uncertainty, the industry evaluated other flow measurement techniques and found the Caldon LEFM Check and LEFM CheckPlus™ultrasonic flow meters to be a viable alternative.

Staff in the Office of Nuclear Reactor Regulation's Instrumentation and Controls Branch reviewed this MUR power uprate based on the LEFM CheckPlus™technology and RIS 2002-03 (Reference 14), as described below.

LEFM Technology and Measurement

Both the Caldon LEFM Check and LEFM CheckPlus™Systems use transit time methodology to measure fluid velocity. The basis of the transit time methodology for measuring fluid velocity and temperature is that ultrasonic pulses transmitted through a fluid stream travel faster in the direction of the fluid flow than through the opposite flow. The difference in the upstream and downstream traversing times of the ultrasonic pulse is proportional to the fluid velocity in the pipe. The temperature is determined using a correlation between the mean propagation velocity of the ultrasound pulses in the fluid and the fluid pressure.

Both systems use multiple diagonal acoustic paths instead of a single diagonal path, allowing velocities measured along each path to be numerically integrated over the pipe cross-section to determine the average fluid velocity in the pipe. This fluid velocity is multiplied by a velocity profile correction factor, the pipe cross-section area, and the fluid density to determine the FW mass flow rate in the piping. The mean fluid density may be obtained using the measured pressure and the derived mean fluid temperature as an input to a table of thermodynamic properties of water. The velocity profile correction factor is derived from calibration testing of the LEFM in a plant-specific piping model at a calibration laboratory.

The Caldon LEFM Check System consists of a spool piece with eight transducers, two on each of the four acoustic paths in a single plane of the spool piece. The velocity measured by any one of the four acoustic paths is the vector sum of the axial and the transverse components of fluid velocity as projected onto the path. The Caldon LEFM CheckPlus™ System uses 16 transducers, 8 each in two orthogonal planes of the spool piece. In the Caldon LEFM CheckPlus™ System, when the fluid velocity measured by an acoustic path in one plane is averaged with the fluid velocity measured by its companion path in the second plane, the transverse components of the two velocities are canceled, and the result reflects only the axial velocity of the fluid. This makes the numerical integration of four pairs of averaged axial velocities and the computation of volumetric flow inherently more accurate than a result obtained using four acoustic paths in a single plane. Also, since there are twice as many acoustic paths and two independent clocks to measure the transit times, errors associated with uncertainties in path length and transit time measurements are reduced.

The NRC staff's review in the area of I&C covers the proposed plant-specific implementation of the FW flow measurement technique and the power increase gained as a result of implementing this technique, in accordance with the guidelines (A through H) provided in Section I of Attachment 1 to RIS 2002-03 (Reference 14), which relates to 10 CFR Part 50, Appendix K. The staff conducted its review to confirm that the licensee's implementation of the proposed FW flow measurement device is consistent with staff-approved Topical Reports ER-80P (Reference 15) and ER-157P (Reference 16) and that the licensee adequately addressed the four additional requirements listed in the staff's SE (Section 3.2, Item D, discusses these four requirements in more detail). The NRC staff also reviewed the power measurement uncertainty calculations to ensure that (1) the conservatively proposed uncertainty value of 0.3 percent correctly accounts for all uncertainties associated with power level instrumentation errors, and (2) the uncertainty calculations meet the relevant requirements of 10 CFR Part 50, Appendix K, as described in Section 2 of this SE.

The licensee provided the information described below regarding the Caldon LEFM CheckPlus™ System FW flow measurement technique and its implementation at St. Lucie 2.

The LEFM systems of St. Lucie 2 contain an individual LEFM metering spool piece on each of the two FW flow headers. Each of the LEFM meters functions independently to calculate a FW mass flow rate. FPL plans to permanently install the LEFM CheckPlus™ System in accordance with the requirements of Topical Reports ER-80P and ER-157P and FPL procedures. The system will provide FW mass flow and FW temperature input data to the DCS, which is the computer system that automatically performs continuous calorimetric power calculations.

The LEFM CheckPlus™ System incorporates self-verification features to ensure that hydraulic profile and signal processing requirements are met within the site-specific design-basis uncertainty analysis. Critical performance parameters, including signal-to-noise ratio, are continually monitored for every individual meter path, and alarm setpoints are established to ensure that the corresponding assumptions in the uncertainty analysis remain bounding. Signal noise will be minimized via strict adherence to Cameron design requirements. Cameron has provided transducer signal cables that meet the design requirements. Processed transducer data from the LEFM transmitters are sent to the LEFM central processing units (CPUs) via RS-485 communication cables.

The LEFM CheckPlus™ System communicates with the DCS via a digital communications interface. Dual data outputs provide redundant information sources for the DCS. The LEFM data sent to the DCS are limited to values actually used in the calorimetric calculations (i.e., FW mass flow rate and FW temperature for each header) and the associated data quality status. The LEFM-based mass flow rate and FW temperature data are to be integrated into appropriate DCS calorimetric display screens. Alarms to the main control room annunciator panels will notify operators of degraded system performance or system failure.

LAR Compliance with RIS 2002-03, Attachment 1, Section I, Guidance A through H

Items A through C

Items A, B, and C in Section I of Attachment 1 to RIS 2002-03 (Reference 14) guide licensees in identifying the approved topical reports, providing references to the NRC's approval of the measurement technique, and discussing the plant-specific implementation of the guidelines in the topical report and the NRC staff's approval of the FW flow measurement technique, respectively.

In its LAR, the licensee identified Topical Reports ER-80P (Reference 15) and ER-157P (Reference 16) as applicable to the Caldon LEFM CheckPlus™ System. The licensee also referenced the NRC SE dated March 8, 1999 (Reference 17), for Topical Report ER-80P, and the SE dated December 20, 2001(Reference 18), for Topical Report ER-157P.

Based on its review of the licensee's submittals as discussed above, the staff finds that the licensee has sufficiently addressed the plant-specific implementation of the Caldon LEFM CheckPlus™ System using proper topical report guidelines. Therefore, the licensee's description of the FW flow measurement technique and implementation of the power uprate using this technique follows the guidance in Items A through C of Section I of Attachment 1 to RIS 2002-03.

Item D

Item D in Section I of Attachment 1 to RIS 2002-03 (Reference 14) guides licensees in addressing four criteria that the NRC staff stated in its SEs(References 17; 18) on Topical Reports ER-80P (Reference 15) and ER-157P (Reference 16), when implementing the FW flow measurement uncertainty technique. The staff's SEs on Topical Reports ER-80P and ER-157P both include these four plant-specific criteria to be addressed by a licensee referencing these topical reports for power uprate. The licensee's submittals address each of the four criteria as follows:

(1) The licensee should discuss the maintenance and calibration procedures that will be implemented with the incorporation of the LEFM. These procedures should include processes and contingencies for an inoperable LEFM and the effect on thermal power measurement and plant operation.

The licensee states that implementation of the power uprate license amendment will include developing the necessary procedures and documents required for operation, maintenance, calibration, testing, and training at the uprated power level with the new LEFM system. Plant maintenance and calibration procedures will be revised to incorporate Cameron's maintenance and calibration requirements before the licensee declares the LEFM system operable and raises power above 2,968 MWt.[1] Items G and H of this SE discuss LEFM system maintenance and calibration procedures and contingency plans for operation of the plant with the LEFM CheckPlus™ System out of service (OOS).

Based on its review of the licensee submittals, the staff concludes that the licensee adequately addressed Criterion 1.

(2) For plants that currently have LEFMs installed, the licensee should provide an evaluation of the operational and maintenance history of the installation and confirmation that the installed instrumentation is representative of the LEFM system and bounds the analysis and assumptions set forth in Topical Report ER-80P (Reference 15).

This criterion is not applicable to St. Lucie 2 since the LEFM CheckPlus™ Systems are not yet installed.

(3) The licensee should confirm that the methodology used to calculate the uncertainty of the LEFM in comparison to the current FW instrumentation is based on accepted plant setpoint methodology (with regard to the development of instrument uncertainty). If an alternative approach is used, the application should be justified and applied to both venturi and ultrasonic flow measurement instrumentation installations for comparison.

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[1] The value of 2,968 MWt is based on operation at the requested EPU power level, but without the MUR power uprate provided by the LEFM. Operation at the EPU power level must be specifically approved.

The licensee provided core thermal power measurement uncertainty for the LEFM system at St. Lucie 2. Those uncertainty calculations are based on proprietary Cameron Engineering Report ER-740 (Reference 19). The licensee stated that calculation methods are based on FPL Nuclear Engineering Department Discipline Standard IC-3.17, Rev. 7, “Instrument Setpoint Methodology for Nuclear Power Plants.” Both the Cameron method and FPL standard are based on ISA RP67.04.02, “Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation” (Reference 20), which is consistent with the guidelines in RG 1.105, Rev. 3, “Setpoints for Safety-Related Instrumentation,” issued December 1999 (Reference 21).

In addition, the licensee needs to perform the postmodification test, which includes verifying LEFM calorimetric calculations using LEFM mass flow and temperatures to ensure that the LEFM is within established limits (Item 5 in Table 2.12-3, “Post-Modification Testing,” of Attachment 5 to the LAR (Reference 2).

Based on the above discussion and its review of the licensee’s setpoint methodology and calculation, the NRC staff concludes that the licensee adequately addressed Criterion 3.

(4) For plant installation where the ultrasonic meter (including LEFM) was not installed with flow elements calibrated to a site-specific piping configuration (flow profiles and meter factors are not representative of the plant-specific installation), licensees should provide additional justification for its use. The justification should show that the meter installation is either independent of the plant-specific flow profile for the stated accuracy, or that the installation can be shown to be equivalent to known calibrations and plant configurations for the specific installation, including the propagation of flow profile effects at higher Reynolds numbers. Additionally, for previously installed calibrated elements, licensees should confirm that the piping configuration remains bounding for the original LEFM installation and calibration assumptions.

The calibration factor (also known as the meter factor) for the St. Lucie 2 flow elements has been established by tests of these spools at Alden Research Laboratory in February 2009. These tests included a full-scale model of the St. Lucie 2 hydraulic geometry and piping arrangement. Cameron Engineering Report ER-736, “Meter Factor Calculation and Accuracy Assessment for St. Lucie 2” (Reference 22) documents test data and results for the flow elements.

Final verification of the site-specific uncertainty analyses occurs as part of the LEFM CheckPlus™ System commissioning process. The commissioning process provides final positive confirmation that actual performance in the field meets the uncertainty bounds established for the instrumentation as described in Cameron engineering reports ER-736 and ER-740.

Based on the information given above and the staff’s review of the licensee’s submitted calibration data in Cameron Engineering Reports ER-736 and ER-740, the NRC staff concludes that the licensee adequately addressed Criterion 4.

Item E

Item E in Section I of Attachment 1 to RIS 2002-03 (Reference 14) guides licensees in the submittal of a plant-specific total power measurement uncertainty calculation, explicitly identifying all parameters and their individual contribution to the power uncertainty.

To address Item E of RIS 2002-03, the licensee provided Cameron Engineering Reports ER-740, Rev. 0 (Reference 19). The licensee lists each contribution's parameters and values for the overall thermal power calorimetric uncertainty in Table 2.4.4-1 of Attachment 5 to the LAR. The uncertainties documented in this table are based on Cameron Engineering Reports ER-736 (Reference 22) and ER-740 (Reference 19).

The staff reviewed the uncertainty calculations and issued RAI regarding the steam moisture carryover assumption and the steam enthalpy uncertainty calculation. In its responses (Reference 23), the licensee provided its expected (actual) moisture carryover percentage at the St. Lucie 2 SG with adequate justification that its assumption is conservative. Therefore, the NRC staff determined that the licensee properly identified all the parameters associated with the thermal power measurement uncertainty, provided individual measurement uncertainties, and calculated the overall thermal power uncertainty.

The licensee's calculations arithmetically summed uncertainties for parameters that are not statistically independent and that are statistically combined with other parameters. The licensee combined random uncertainties using the square-root-sum-of-squares approach and added systematic biases to the result to determine the overall uncertainty. This methodology is consistent with the vendor's determination of the uncertainty of the Caldon LEFM CheckPlus™ System, as described in the referenced topical reports, and is consistent with the guidelines in RG 1.105, Rev. 3 (Reference 21).

As a result, the NRC staff finds that the licensee has provided calculations of the total power measurement uncertainty at the plant, explicitly identifying all parameters and their individual contributions to the overall thermal power uncertainty. Therefore, the licensee has adequately addressed the guidance in Item E of Section I of Attachment 1 to RIS 2002-03.

Item F

Item F in Section I of Attachment 1 to RIS 2002-03 (Reference 14) guides licensees in providing information to address the specified aspects of the calibration and maintenance procedures related to all instruments that affect the power calorimetric.

In the LAR, the licensee addressed each of the five aspects of the calibration and maintenance procedures listed in Item F of RIS 2002-03 related to all instruments that affect the power calorimetric as follows:

(1) Maintaining Calibration

The licensee stated that the calibration and maintenance are performed by I&C maintenance department personnel working under the site work control processes and using site-specific procedures. The site-specific procedures are to be developed using Cameron technical manuals. Selected I&C personnel will be trained and qualified according to the Institute for Nuclear Power Operations [INPO] accredited training program for the St. Lucie Station before maintenance or calibration is performed and before increasing power above 2,968 MWt (approval to operate at this power level is contingent on the approval of the EPU).

(2) Controlling Hardware and Software Configuration

The Cameron LEFM CheckPlus™ System is designed and manufactured in accordance with the vendor's QA program, which meets the requirements of Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50. The licensee stated that the LEFM software is controlled on site by FPL's software QA program, which includes configuration control via the Master Software Index, Software Classification Determination, Software QA Plan, Software Requirements Specification, Software Design Description, Software Verification and Validation Plan, Backup/Recovery Contingency Planning, and QA Record Storage. A design change program controls the LEFM hardware changes.

(3) Performing Corrective Actions

Maintenance department I&C personnel, qualified in accordance with the St. Lucie I&C training program and formally trained on the LEFM CheckPlus™ System, perform corrective action involving maintenance. The licensee documents and evaluates any conditions that are adverse to quality under the site CAP.

(4) Reporting Deficiencies to the Manufacturer

Equipment problems for all plant systems, including the LEFM equipment, fall under the site work control process or the corrective action process. The licensee documents and evaluates conditions adverse to quality under the CAP and subsequently transmits them to the vendor as appropriate.

(5) Receiving and Addressing Manufacturer Deficiency Reports

The St. Lucie 2 LEFM CheckPlus™ System will be included in Cameron's verification and validation program, and procedures are maintained for user notification of important deficiencies. The LEFM CheckPlus™ System purchase agreement with FPL includes requirements that Cameron inform FPL of any deficiencies in accordance with Cameron's maintenance agreement and/or 10 CFR Part 21, "Reporting of Defects and Noncompliance."

The NRC staff's review of the above information found that the licensee addressed the calibration and maintenance aspects of the Caldon LEFM CheckPlus™ System and all other instruments affecting the power calorimetric. Thus, the licensee meets the guidance in Item F of Section I of Attachment 1 to RIS 2002-03.

Items G and H

Items G and H in Section I of Attachment 1 to RIS 2002-03 (Reference 14) guide licensees to provide a proposed allowed outage time (AOT) for the instrument and to propose actions to reduce power if the AOT is exceeded.

The licensee discussed the proposed AOT and various LEFM operating modes as described below.

FPL proposed that the AOT for operation at any power level in excess of 2,968 MWt with the Cameron LEFM CheckPlus™ System OOS, is 48 hours, provided that steady-state conditions persist (i.e., there are no power changes in excess of 10 percent) throughout the 48-hour period. The 48-hour "clock" starts at the time of the LEFM CheckPlus™ System failure.

Since the licensee proposed various maximum power levels with three LEFM maintenance modes, the staff issued an RAI to request a list of the maximum power levels for all LEFM maintenance modes and other OOS conditions after the AOT expires. In response, the licensee provided a table that outlines the maximum MWt for all LEFM operating conditions when the 48-hour AOT expires. The NRC staff verified each value of those maximum allowable power levels in the following table provided by the licensee:

Maximum MWt	**Total Power Uncertainty %**	**LEFM Operating Condition**
3,020	0.30%	System Fully Functional
3,015	0.46%	One Section (Plane) of One LEFM in Maintenance
3,013	0.50%	One Section (Plane) of Both LEFMs in Maintenance

Additionally, with any one of the two LEFM meters OOS, the maximum MWt is limited to 2,968 MWt following the 48-hour AOT.

The licensee provided the following bases for the AOT and the proposed power reduction following the 48-hour AOT:

- The mass flow rate data (based on the venturis, DP transmitters, and RTDs) is normalized to the Cameron LEFM CheckPlus™ System mass flow rate on a periodic basis. This periodic normalization provides a seamless transition at the time of an LEFM OOS condition. Over a 48-hour period, with the plant at stable full-power conditions, the errors due to venturi nozzle fouling and transmitter drift are not significant according to the review of plant calibration records.

- The LEFM system, including the interface to the DCS, has been designed to be fault tolerant. The LEFM system includes two physically separate and redundant CPUs, each capable of processing the data from both LEFM spool pieces. The active CPU data source for the DCS calorimetric calculations will be automatically swapped by the DCS when necessary based on quality status flags of LEFM and the Ethernet interface module between LEFM and DCS. Redundant processors are used within the DCS with automatic fail-over logic. In the unlikely event that the automated DCS based calorimetric power calculation was not available, manual calorimetric calculations would be performed in accordance with existing plant procedures.

- As a conservative measure, the FSAR Section 13.8, “Licensee-Controlled TS Requirements,” will restrict plant power to less than or equal to 2,968 MWt if the automated calorimetric portion of the DCS cannot be restored within 48 hours.

- If the plant experiences a power change of greater than 10 percent during the 48-hour period, then power level will be restricted to less than or equal to 2,968 MWt until the LEFM CheckPlus™ System is fully functional.

- As described above, the St. Lucie 2 configuration will include separate LEFM flow elements (spool pieces), one for each of the two FW headers. These LEFM subsystems (meters) function independently of each other to calculate a mass flow rate for each of the two FW headers. Each LEFM CheckPlus™ meter consists of two meter sections of transducers. Each LEFM meter section includes four signal paths arranged in a plane that is orthogonal to the four signal paths of the other meter section. In effect, each LEFM CheckPlus™ meter section is functionally equivalent to the previous generation LEFM Check meter. In accordance with the site-specific uncertainty analysis (Cameron ER-740 (Reference 19)), a loss of one section of one meter results in 0.46-percent uncertainty versus 0.30-percent uncertainty with both sections of both meters operable. FSAR Section 13.7 will include an action statement to specify that if either LEFM meter has experienced a failure of only one section (four paths) of the system, then plant power will be limited based on a total calorimetric uncertainty of 0.46 percent.

- The site-specific uncertainty analysis (Cameron ER-740) also documents a system-level uncertainty of 0.50 percent for a postulated failure of one section in both LEFM CheckPlus™ meters. FSAR Section 13.7 will include an action statement to specify that if both LEFM subsystems (meters) have experienced a failure of only one section (four paths), then plant power will be limited based on a total calorimetric uncertainty of 0.50 percent.

- The site-specific uncertainty analysis already considers the unavailability of certain LEFM system redundant subcomponents (including a single CPU, a single FW pressure transmitter, and a single steam header pressure transmitter). Since the unavailability of these subcomponents has no adverse effect on the bounding calorimetric uncertainty, FSAR Section 13.7 will specify those components that may be removed from service without any corresponding reduction in plant power.

- If the 48-hour outage period is exceeded, then the plant will operate at a power level consistent with the accuracy of the alternate plant instruments. The action statement requirements for power reduction are to be in accordance with current operating procedures, such that the plant will be operating at or below the specified power limit by the time the 48 hours has elapsed.

The staff reviewed Cameron Engineering Reports ER-736 (Reference 22) and ER-740 (Reference 19), which list the meter factors of flow calibration for LEFM CheckPlus™ normal, plane A, and plane B (i.e., maintenance mode—LEFM CheckPlus™ with only one transducer plane failed) separately for each flow calibration test at Alden Research Laboratory. The staff found that in effect, each LEFM CheckPlus™ System meter section is functionally equivalent to the previous generation LEFM Check meter with the proper meter factor. In accordance with the site-specific uncertainty analysis (Cameron Engineering Report ER-740), failures of one plane of one meter and two meters result in total calorimetric uncertainties of 0.46 percent and 0.50 percent, respectively, as shown in the table above. However, based on the principles of simple decisionmaking and conservative plant operation, the staff determined that only one maintenance mode is acceptable; that is, the plant will be operated as follows:

Maximum MWt	**Total Power Uncertainty %**	**LEFM Operating Condition**
3,020	0.30%	System Fully Functional
3,015	0.46%	One Section (Plane) of Any One LEFM in Maintenance
2,968	2.0%	Dual Section (Plane) Failure of Any LEFM Meters or Any Other OOS

The licensee will establish plant procedures based on these calculated uncertainties to set power limitations for maintenance conditions.

Based on the above discussion and the staff's review of the licensee's LAR, RAI responses, and Cameron engineering reports, the NRC staff finds that the licensee provided sufficient justifications for the proposed AOT and the proposed power reduction actions if the AOT is exceeded. Therefore, the licensee has followed the guidance in Items G and H of Section I of Attachment 1 to RIS 2002-03 (Reference 14).

Conclusion

The Instrumentation and Controls Branch staff reviewed the licensee's proposed plant-specific implementation of the FW flow measurement device and the power uncertainty calculations. Based on its review of the licensee's LAR, RAI responses, uncertainty calculations, and referenced topical reports, the staff finds that the licensee's proposed amendment is consistent with the approved Caldon Topical Report ER-80P (Reference 15) and its supplement, Topical Report ER-157P (Reference 16). The staff also finds that the licensee adequately accounted for all instrumentation uncertainties in the total thermal power measurement uncertainty calculations and demonstrated that the calculations meet the relevant requirements of Appendix K to 10 CFR Part 50 and NRC RIS 2002-03 (Reference 14), as described in Section 2 of this SE. The licensee has committed to the following action:

> Final verification of the site-specific uncertainty analyses occurs as part of the LEFM CheckPlus™ system commissioning process. The commissioning process provides final positive confirmation that actual performance in the field meets the uncertainty bounds established for the instrumentation as described in Cameron engineering report ER-736 (page 2.4.4-5, paragraph 2 of Attachment 5 to the LAR).

Therefore, the staff concludes that the I&C aspect of the proposed MUR thermal power uprate of 1.7 percent is acceptable.

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

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.

Technical Evaluation

In Section 2.5.1.1.1 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on flood protection analysis in comparison to its current design basis described in the FSAR for St. Lucie 2. The specific FSAR section evaluated by the licensee was Section 3.4.3, Reactor Auxiliary Building (RAB) Internal Flooding Due to Equipment Failure. The licensee's assessment of the safety-related equipment in the RAB determined that flooding conditions would not impact the ability of equipment to achieve safe shutdown during post-EPU operation. The licensee based its conclusion on current St. Lucie 2 mitigation procedures to isolate the ECCS pump room from fluid, which would come from non-seismic tanks during a seismic event. Plant procedures would require personnel to isolate the ECCS pump room and protect the safety-related equipment within the ECCS pump room. During EPU conditions, the licensee indicated that this analysis will remain valid. The amount of fluid in the non-seismic tanks will be unchanged and no additions or changes are being made to the components currently in the RAB. The licensee also stated that the EPU does not affect the location of existing safety-related equipment in the RAB or require any additions to the safety-related equipment required for safe shutdown of the plant

The staff evaluated the licensee's FSAR references along with the GDC 2 and GDC 4 criteria for flood protection. The staff determined that the licensee's assessment of flood protection at St. Lucie 2 during EPU conditions is acceptable because no changes are being made to the physical components that are included in RAB and the flooding evaluation of the RAB will remain the same for EPU conditions. Therefore, the staff concluded that protection against external and internal flooding remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

Conclusion

The NRC staff has reviewed the proposed changes in fluid volumes in tanks and vessels for the proposed EPU. 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to flood protection.

2.5.1.1.2 Equipment and Floor Drains

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 EPU 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 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.

Technical Evaluation

In Section 2.5.1.1.2 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the EFDS in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR section evaluated by the licensee was Section 9.3.3, Equipment and Floor Drainage System. The licensee also evaluated IE Notice 83-044, "Potential Damage to Redundant Safety Equipment as a Result of Backflow Through the Equipment and Floor Drain System," for any impacts of the proposed EPU on the evaluation performed for potential backflow through the EFDS. The licensee determined through its assessment that the proposed EPU would not impact the seismic design of components in the EFDS nor add or modify equipment in the St. Lucie 2 reactor building, RAB, or FHB that would result in increasing the quantities of liquids currently entering the EFDS. The licensee also determined that there are no changes to the EFDS that would allow contaminated fluids to be inadvertently transferred to an uncontaminated drainage system. The licensee further determined that its assessment of IE Notice 83-044 remains valid for EPU conditions, in which the licensee previous assessed that the scenario of flooding damage into safety-related equipment caused by backflow through the EFDS could not occur at St. Lucie 2. The staff evaluated the licensee's assessment of the proposed EPU effects on the EFDS according to GDC 2 and GDC 4. The staff evaluated the licensee's RAI response and determined that its assessment of the EFDS is acceptable due to no physical or design changes being made to the EFDS to support EPU conditions. The staff also finds the licensee's assessment of internal flooding effects on the EFDS acceptable. Therefore, the staff concluded that the EFDS remains consistent with the St. Lucie 2 licensing basis and acceptable for proposed EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU 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 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EFDS.

2.5.1.1.3 Circulating Water System

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove excess heat from the turbine cycle and auxiliary systems. For proposed power uprates, the staff's review of the CWS includes evaluating the impact that the proposed uprate 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. Although the circulating water system flow rate and operating pressure changes slightly as a result of main condenser modifications to support operation at EPU conditions, there are no modifications to the circulating water pumps or system that would increase the maximum flow from a rupture in the system. Accordingly, the analyses and design features related to internal flooding due to leakage or a break in the circulating water system for current plant conditions are unaffected by the EPU.

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

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 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.

Technical Evaluation

In Section 2.5.1.2.1 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the internally generated missiles analysis in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR section evaluated by the licensee was FSAR Section 3.5, Missile Protection. The licensee's assessment of internally generated missiles focused on any increase in system pressure or component overspeed conditions due to implementation of EPU that could result during plant operation, AOOs, or changes in existing system configurations such that missile barriers could be affected. The licensee concluded that the proposed EPU would not affect the existing missile barrier protection measures due to no system or equipment changes being made. The licensee also determined that the existing missile analysis for St. Lucie 2 will remain valid for EPU conditions due to no operating pressures not increasing for the reactor coolant and main steam systems.

The staff reviewed the licensee's assessment of internally generated missiles for the proposed EPU according to GDC 4. The staff finds the licensee's assessment acceptable due to no changes being made to any systems and components that are currently part of the existing missile analysis for St. Lucie 2 and the current analysis remains valid for EPU conditions. The staff identified no other modifications with the potential to affect missile protection of safety-related components outside containment. Therefore, the staff concluded that the licensee's internally generated missiles analysis remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

Conclusion

The NRC staff has reviewed the changes in system pressures and configurations that are required for the proposed EPU 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to internally generated missiles.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The TCS, steam inlet stop and control valves, low pressure turbine steam intercept and inlet control valves, and extraction steam control valves control the speed of the turbine under normal and abnormal conditions, and are thus related to the overall safe operation of the plant. The NRC staff's review of the turbine generator focused on the effects of the proposed EPU on the turbine overspeed protection features to ensure that a turbine overspeed condition above the design overspeed is very unlikely. The NRC's acceptance criteria for the turbine generator are based on GDC 4, and relates to protection of SSCs important to safety from the effects of turbine missiles by providing a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generating turbine missiles. Specific review criteria are contained in SRP Section 10.2.

Technical Evaluation

In Section 2.5.1.2.2 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the turbine generator with regards to missile protection analysis in comparison to its current design basis as described in the St. Lucie 2 FSAR. Specific FSAR sections evaluated by the licensee were Section 3.5, Missile Protection; Section 7.7, Control Systems Not required for Safety; and Section 10.2, Turbine Generator. The licensee provided a detailed description of the turbine generator and control systems as well as the over speed protection. The licensee also described its missile generation analysis used for St. Lucie 2 and the impact of the proposed EPU. The licensee made the following conclusions in regards to effects of the EPU on turbine generator under EPU conditions:

- The normal operating turbine running speed of 1800 rpm will not change as a result of the power uprate and its associated modifications.

- The design overspeed limit of 120-percent will not change as a result of the power uprate.

- Maintenance, inspection and testing associated with the turbine rotors and the turbine overspeed control system, including frequencies of these activities, will not change as a result of the EPU.

- The existing 18 month fuel cycle conditional probability of destructive overspeed value of 2.58E-6 per year will remain unchanged after EPU and its associated modifications. This conditional probability assumes system separation as a precursor event and is based on a 6 month turbine valve test interval.

- The probability value of the precursor system separation event of 5.40E-02 is unchanged by the EPU. Therefore, the probability of generating a destructive overspeed missile, which is taken as the product of the system separation and above conditional probability values, remains at a value of 1.39E-07/year under EPU conditions.

- Material properties of the replacement rotors along with their physical properties will be considered in the generation and growth of disk cracks and the potential generation and ejection of missiles originating from the failure of these new turbine disks in the evaluation of the EPU design condition.

The licensee also stated that the two existing low pressure turbines will be replaced with new Siemens-supplied replacement turbines prior to the implementation of the EPU. In addition, the high pressure (HP) rotor will be replaced due to the increased volumetric flow requirements under the proposed uprate condition. The licensee indicated that these modifications to the turbine generator will result in a significant overall increase in the compound turbines moment of inertia as compared to the existing unit. However, the licensee stated that the effects will be "…somewhat offset by the operational changes of higher pressure and power output, as well as, by the increased efficiency of the replacement rotors."

In addition to the physical changes to the low pressure and HP turbines, the licensee also stated that the Overspeed Protection Controller (OPC), the associated OPC solenoid valves, the emergency trip turbine trip solenoid valve and the mechanical overspeed trip device are planned to be replaced as part of an overall TCS upgrade to improve reliability and maintainability. The revised TCS will be provided by Westinghouse, which is called Ovation, and will be based on a standard design previously installed for other US nuclear power plants. Two independent overspeed protection systems will be provided and each of these systems will include two out of three redundancies for speed sensing and turbine trip solenoid valve logic. The licensee justified this change to the TCS due to a topical report provided by Westinghouse, WCAP-16501 "Extension of Turbine Valve Test Frequency Up to 6 Months for BB-296 Siemens Power Generation Turbines with Steam Chests, Rev.0."

In addition to the changes to the overspeed protection system, the licensee indicated that the proposed EPU will increase the power level and amount of trapped energy in the power generation system that taken independent of other changes would result in an increase in the expected peak turbine overspeed. However, the licensee determined that the power increase and the volume increase due to moisture separator reheater and FW heater changes will be offset by changes associated with the new replacement turbine rotors. The licensee also performed an evaluation to establish the post-EPU overspeed condition based on both the increased power and flow levels, as well as, the physical changes of the replacement rotors. The licensee concluded that the increased inertia of the rotors outweighed the impact due to the power increase from the uprate such that the net effect was a 1-percent reduction in the expected overspeed of the turbine.

The licensee also performed a revised turbine missile generation analysis on the low pressure rotors. The revised analysis focused on the changes to the normal operating condition and the new low pressure rotors to establish a revised probability for both the postulation of a low pressure rotor disk failure and the probability of a disk section exiting the casing given this failure. The licensee's assessment of the probability of the low pressure rotors missile generation due to run-away overspeed was based upon the original TCS values, in which the licensee found to be conservative.

The staff reviewed the licensee's assessment of the effects of proposed EPU on the turbine generator and the revised missile generation analysis for the low pressure rotors according to GDC 4. The staff found that the licensee did not provide justification for using the Siemens rotors with the revised Westinghouse TCS. The staff issued RAI SBPB-4, by email dated August 17, 2011, to the licensee for further information describing the compatibility of the Siemens rotors with the revised TCS. The licensee provided its RAI response, by letter dated October 12, 2011, with additional information on the turbine missile generation analysis regarding the low pressure rotors. The licensee referenced the NRC's SE (Reference 24), which accepted the Siemens Westinghouse Topical Report TR-TP-04124, "Missile Probability Analysis for the Siemens 13.9M Retrofit Design of Low-Pressure Turbine by Siemens AG." The licensee used the topical report to provide its basis for using the new Siemens low pressure rotors with the revised Westinghouse TCS and concluded the current design analysis for missile protection along with the testing and maintenance requirements would remain consistent for EPU conditions.

Section 3.5 of the St. Lucie 2 FSAR specifies that missile barrier protection is based on missiles generated by disk failure at design overspeed of 120 percent, which does not encompass overspeed protection system failure. The Siemens Westinghouse Topical Report TR-TP-04124, provides an NRC-accepted licensing basis for failures at or below design overspeed, but the EPU licensing report does not clearly specify this analysis as the new licensing basis for protection against failure of the replacement rotors at or below design overspeed at EPU conditions. This topical report does not include an applicable evaluation of destructive overspeed failure probability. The licensee also cited in the EPU licensing report and in its response to RAI 2.5.1.2.2 that the WCAP-16501-P provides analyses for overspeed protection system failures for several plants, including St. Lucie 2. However, the licensee indicated that the overspeed protection system would be replaced with the Ovation turbine control and protection system. The licensee's RAI response also stated that the Ovation system enhances control system reliability and continued usage of the existing overspeed protection system failure probability in the overspeed protection analysis cited in WCAP-16501 is conservative.

Although the staff found the licensee's assessment of the applicability of the Topical Report TR-TP-04124, the staff found the licensee's initial RAI response regarding the overspeed protection system failure probability, along with the testing and maintenance requirements, for the turbine generator unacceptable. The staff initially rejected the licensee's use of WCAP-16501 as justification for the overspeed protection analysis because the report is not applicable to the proposed new turbine overspeed protection system. The staff also disagreed with the licensee's initial assessment that the existing testing and maintenance requirements for the previous TCS will be applicable to the new Ovation system since the new system has not been formally tested with the EPU parameters at St. Lucie 2. The staff transmitted a follow-up RAI to the licensee on November 15, 2011 for clarification of the proposed EPU licensing basis for protection against failure at or below design overspeed and provide a detailed technical basis for the continued use of the existing overspeed protection system failure probability with the Ovation overspeed protection system. The staff requested the licensee to address as part of its response the changes in design (e.g., elimination of mechanical overspeed trip), potential for common cause/mode failure of redundant components, potential for latent failures undetected by testing of trip paths, and commitments to turbine steam admission valve and overspeed trip system testing at frequencies necessary to support the proposed reliability.

The licensee provided its supplemental response to the RAI, by letter dated December 14, 2011, with a detailed discussion of its technical basis for using the new Ovation overspeed protection system with the existing criteria for the turbine generator. In the supplemental response, the licensee clarified that the Siemens Westinghouse Topical Report TP-04124 (and its associated Technical Report CT-27332, Rev. 2), "Missile Probability Analysis for the Siemens 13.9 M2 Retrofit Design of Low-Pressure Turbine by Siemens AG," would form the St. Lucie 2 licensing basis for evaluation of turbine failures at or below design overspeed at EPU conditions. Since the NRC staff approved the methodology and issued a final SE for CT-27332, Rev. 2 on March 30, 2004 (ADAMS Accession No. ML040410360), the revised licensing basis is acceptable.

The licensee referenced the WCAP-16501-P as its technical justification for using a six month steam admission valve testing interval at St. Lucie 2 as opposed to the three month interval proposed in the Siemens Westinghouse Topical Report TP-04124. The licensee provided extensive detail as part of in the supplemental response to indicate that the effect of the Ovation overspeed protection system on the conditional probability of destructive overspeed is negligible for both intervals and the system reliability and overspeed probability are bounded by the current analysis for post-EPU conditions.

The licensee also referenced NUREG-1793, Supplement 2, "AP1000 Design Certification Amendment, Advanced Final Safety Evaluation Report, Chapter 10 - Steam and Power Conversion" (ADAMS Accession No. ML100910522) as part of its technical justification for using the new Ovation overspeed protection system for the turbine generator during EPU conditions. The licensee indicated that the Ovation overspeed protection system's logic platform is similar to the platform integrated into the AP1000 Advanced Light Water Reactor standard design that was evaluated and accepted by the NRC. The licensee also provided additional details in its supplemental response addressing how the Ovation overspeed protection system improves upon the current overspeed protection system at St. Lucie 2 and the functionality of the new Ovation overspeed protection system will remain bounded by the WCAP-16501-P analyses for St. Lucie 2 during EPU conditions.

The licensee also provided a set of the following commitments to address the testing and functionality of the new Ovation overspeed protection system as stated for Acceptance Criteria 11.1 in Section 10.2 of the SRP:

- Testing of the speed probes will be performed off-line at refueling intervals. The analog signals are displayed for channel comparison. The analog signal quality discrimination is always active and an alarm occurs on speed deviation between any two of the three channels (for both passive and active probe sets).

- Testing of the Speed Detector Modules will be performed off-line at refueling intervals.

- Testing of the Testable Dump Manifolds will be performed on-line (one channel at a time) at a quarterly interval.

- Testing of the TCS Controller overspeed logic will be performed during startup at a refueling interval. This test will verify overspeed trip capability of the redundant controllers. The test will be conducted at a reduced setpoint. The setpoint is automatically returned to the overspeed trip setting following termination of the overspeed trip test. The reduced setpoint is used to minimize turbine stresses that occur during overspeed conditions.

- Testing of the steam admission valves will occur at the current 6 month interval.

The staff reviewed the licensee's supplemental response for using the new Ovation overspeed protection system using the existing criteria for the turbine generator missile generation analysis and finds that the licensee's assessment meets GDC 4. The staff also finds that the licensee provided adequate justification for using the 6 month steam admission valve testing interval as opposed to the three month interval. The staff also finds that the licensee adequately addressed how the technical attributes of the new Ovation overspeed protection system will exceed the performance of the current overspeed protection system evaluated in the overspeed protection analysis for St. Lucie 2 under EPU conditions. The staff also finds the testing commitments for the new Ovation overspeed protection system to be acceptable for EPU implementation. Therefore, the staff concluded that the licensee's analysis for the turbine generator remains consistent with the St. Lucie 2 licensing basis and acceptable for proposed EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the turbine generator and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on turbine overspeed. The NRC staff concludes that the turbine generator will continue to provide adequate turbine overspeed protection to minimize the probability of generating turbine missiles and will continue to meet the requirements of GDC 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the turbine generator.

2.5.1.3 Pipe Failures

Regulatory Evaluation

The NRC staff conducted a review of the plant design for protection from piping failures outside containment to ensure that (1) such failures would not cause the loss of needed functions of safety-related systems and (2) the plant could be safely shut down in the event of such failures. The NRC staff's review of pipe failures included high and moderate energy fluid system piping located outside of containment. The NRC staff's review focused on the effects of pipe failures on plant environmental conditions, control room habitability, and access to areas important to safe control of post-accident operations where the consequences are not bounded by previous analyses. The NRC's acceptance criteria for pipe failures are based on GDC 4, which requires, in part, that SSCs important to safety be designed to accommodate the dynamic effects of postulated pipe ruptures, including the effects of pipe whipping and discharging fluids. Specific review criteria are contained in SRP Section 3.6.1.

Technical Evaluation

In Section 2.5.1.3 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the pipe failures analysis in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR section evaluated by the licensee was Section 3.6, "Protection against Dynamic Effects Associated with the Postulated Rupture of Piping." The licensee evaluated the following systems outside containment with current HELB analyses for EPU conditions:

- Main Steam system
- Main FW system
- CVCS
- SG Blowdown system
- Auxiliary Steam system
- Steam supply to AFW pump turbine

The licensee's criteria, as provided in FSAR Section 3.6.1.3, for high and moderate energy pipe rupture analyses both inside and outside containment are:

- If the postulated pipe failure results in an automatic separation of the turbine generator from the power grid, then offsite power is assumed to be unavailable.

- Operator action to mitigate the consequences of the postulated pipe failure, if required, is analyzed for each specific event. The feasibility of initiating operator actions on a timely basis, as well as the accessibility provided to allow the operator actions, is demonstrated.

- The use of required plant systems, including non-seismic systems, in bringing the plant to a safe shutdown condition, is considered in the analysis of pipe failures.

- An unrestrained whipping pipe is considered capable of:

    1) rupturing impacted pipes of smaller nominal pipe sizes, and

    2) developing through-wall leakage cracks in larger nominal pipe sizes with thinner wall thicknesses.

In addition to the criteria given in FSAR Section 3.6.1.3 for both high energy and moderate energy line breaks inside and outside containment, the licensee also assessed the effects of the EPU on the current flooding analysis, found in FSAR Appendix 3.6F, for moderate energy piping failures outside containment that could impact safety-related systems. The following criteria and assumptions used for the current flooding analysis, which are related to moderate energy line breaks outside containment, are:

- Floor drainage system, sump pumps, etc, are considered available to mitigate the flooding consequences of the piping failure.

- Rate of flow from cracks is assumed to be constant until operator isolates the crack or source volume is depleted.

- The locations of postulated cracks in the moderate energy piping systems are not based on stress criteria. The crack is assumed to be located anywhere along the run of pipe for the flooding analysis.

- Moderate energy fluid system pipe failures are considered separately as a single postulated independent event occurring during normal plant operation.

- No operator action such as closing or opening a valve, stopping or starting a pump is assumed for 30 minutes from the first alarm indication in the control room.

- Full and part height barriers separating compartments analyzed for flooding are completely watertight. Penetrations connecting compartments are provided with watertight boot seals that have a design temperature of 400 ºF.

The following areas, which include the safety-related systems as possibly affected by the current flooding analysis for moderate energy line breaks outside containment are:

- ECCS room in RAB
- SDC HX room
- Boric Acid Make-up Tank room
- Charging Pump room
- Diesel Generator building
- Diesel Oil Tank enclosure
- Intake Cooling Water Pump area
- CCW building
- Letdown HX room
- Boric Acid Concentrator room
- Pipe tunnels

- Fuel Pool HX room
- Fuel Pool Pump room
- Fuel Pool Purification Pump room.

The operation of the facility at EPU conditions may affect the environment and dynamic effects of postulated pipe breaks. Operation at EPU conditions can result in higher internal P-T, which may result in additional piping being classified as high-energy piping or result in new postulated break locations in existing piping. The change in internal conditions may also produce harsher environmental conditions or greater dynamic effects as a result of a break. Finally, changes in flow rates or system fluid inventory may increase the effects of flooding from high or moderate energy piping.

The licensee assessed the affect of EPU operation on the classification of piping segments and concluded that operation at EPU conditions would result in no new high energy lines outside containment. The licensee also concluded that the EPU would not result in any new pipe break locations in piping outside containment. The licensee also stated that no modifications are being made to any of the systems that would impact the pipe failure analyses.

The licensee determined that the temperature and pressure increases resulting from operation at EPU conditions are either minimal or have no effect at all on the piping failure analyses for the systems. The licensee found that the temperature and pressure effects associated with ruptures outside containment in the letdown line, charging line, and SGBS lines remain unchanged for EPU conditions. Also, the licensee found that the environmental effects of postulated breaks in the main FW, AFW, branch main steam, and auxiliary steam lines would remain bounded by postulated MSLBs and remain enveloped by the existing EQ profile. The licensee also concluded that the EPU does not affect the current evaluation of flooding in the AFW pump area due to high energy lines breaks as well as the current evaluations of flooding due to moderate energy line failures in the areas identified above.

The staff reviewed the licensee's assessment of pipe failures against the requirements of GDC 4, as modified by the facility's CLB. The staff agrees that the effects of operation at EPU conditions on system operating P-T are typically small and within the bounds of existing analyses. As a result, the EPU would not affect the protection of SSCs important to safety due to postulated pipe failures. Therefore, the staff found the accommodation of environmental effects and the protection against the dynamic effects of pipe failures acceptable for EPU conditions.

Conclusion

The NRC staff has reviewed the changes that are necessary for the proposed EPU and the licensee's proposed operation of the plant, and concludes that SSCs important to safety will continue to be protected from the dynamic effects of postulated piping failures in fluid systems outside containment and will continue to meet the requirements of GDC 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protection against postulated piping failures in fluid systems outside containment.

2.5.1.4 Fire Protection

Regulatory Evaluation

The purpose of the fire protection program is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary plant safe-shutdown functions or significantly increase the risk of radioactive releases to the environment. The NRC staff's review focused on the effects of the increased decay heat on the plant's safe-shutdown analysis to ensure that SSCs required for the safe-shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe-shutdown following a fire. The NRC's acceptance criteria for the fire protection program are based on (1) 10 CFR 50.48, "Fire protection," insofar as it requires the development of a fire protection program 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 the SRP, Section 9.5.1.1, "Fire Protection Program," as supplemented by the guidance provided in Attachment 1 to Matrix 5 of Section 2.1 of RS-001, Rev. 0, "Review Standard for Extended Power Uprates." St. Lucie 2 was licensed to operate on June 10, 1983; and is a CE PWR NSSS.

The St. Lucie 2 fire protection program describes the fire protection features of the plant necessary to comply with Branch Technical Position (BTP) Auxiliary and Power Conversion Systems Branch (APCSB) 9.5-1, Appendix A, dated August 23, 1976. The SER, dated August 17, 1979 and its supplements, describe the approved fire protection program for St. Lucie 2. The SER and supplements are listed in the St. Lucie 2 operating license. In addition to the SER and supplements, the St. Lucie 2 fire protection program was evaluated for plant license renewal. The evaluation is documented in NUREG-1779, "Safety Evaluation Report Related to the License Renewal of the St. Lucie Nuclear Plant, Units 1 and 2," dated July 2003.

Technical Evaluation

FPL developed the LAR utilizing the guidelines in RS-001, Rev. 0, *Review Standard for Extended Power Uprates*. In the LAR, the licensee evaluated the applicable SSCs and safety analyses at the proposed EPU core power level of 3020 MWt. The staff's review of the February 25, 2011, LAR, Section 2.5.1.4., "Fire Protection," Attachment 5 to L-2011-021, identified areas in which additional information was necessary to complete the review of the proposed EPU LAR. In an email dated July 26, 2011, the staff issued an RAI. By the letter dated August 18, 2011, FPL responded to the staff RAI as discussed below.

In RAI AFPB-1, the staff noted that Attachment 1 to Matrix 5 ("Supplemental Fire Protection Review Criteria, Plant Systems"), of NRR RS-001, Rev. 0, *Review Standard for Extended Power Uprates*, states that "power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire. However, the licensee's LAR should confirm that these elements are not impacted by the extended power uprate." The staff noted that LAR, Attachment 5, to L-2011-021, "Licensing Report," Section 2.5.1.4.2.3, on page 2.5.1.4-8, specifically addresses only items (1) through (4) above. The staff requested that the licensee provide statements to address item (5).

In its response the licensee stated that the FPL takes credit for limited repairs (i.e., inserting fuses) to cold shutdown equipment. The EPU does not impact plant procedures or resources required for the above limited repairs to achieve and maintain cold shutdown. Additionally, the proposed EPU does not create the need for any new repairs of systems required to achieve and maintain cold shutdown.

The licensee's response satisfactorily addresses the staff's concerns, and this RAI issue is considered resolved based on the following: The licensee indicated FPL takes credit for limited repairs (i.e., inserting fuses) to cold shutdown equipment and the proposed EPU condition does not impact plant procedures required for repairs to achieve and maintain cold shutdown. Further, the licensee indicated that the proposed EPU condition does not create the need for any new repairs of systems required to achieve and maintain cold shutdown. Since the element is not impacted by the EPU, the staff finds the response acceptable.

In RAI AFPB-2, the staff stated that some plants credit aspects of their fire protection system 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). If St. Lucie 2 credits its fire protection system in this way, the staff requested that the LAR identify the specific situations and discuss to what extent, if any, the extended power and MUR uprates affect these "non-fire-protection" aspects of the plant fire protection system. If St. Lucie 2 does not take such credit, the staff requested that the licensee verify this as well. The staff further requested that the licensee discuss how any non-fire suppression use of fire protection water will impact the need to meet the fire protection system design demands.

In its response the licensee stated that the St. Lucie 2 does not credit the fire water pumps or the dedicated fire water supply for non-fire protection functions during normal plant operations. Non-fire protection uses of other features of the fire protection system are as follows.

1. The fire protection system is capable of providing alternative makeup service water to the CCW surge tank if the demineralized water system (DWS) is not available; and

2. Plant procedures address use of fire protection water as an alternate source of makeup water to the SFP.

Further the licensee stated that two separate storage tanks are provided for the plant fire suppression systems. Each storage tank contains an administratively controlled minimum volume of 300,000 gallons of water. Vertical standpipes are provided within the tanks for non-fire related connections which assure a minimum quantity of water (200,000 gallons) sufficient for a 2-hour supply. This is the maximum water demand required for protecting areas containing safe shutdown equipment. The licensee stated that there is no impact to the fire protection system due to implementation of the EPU. The available volume of fire protection water remains the same as prior to implementation of EPU.

In its response the licensee indicated that, during off-normal or emergency conditions, FPL will employ features of the fire protection system as necessary to ensure the safe operation of the plant. Procedural guidance is provided to ensure the fire system remains capable of responding to a fire if applicable. Provisions for using fire water for off-normal or emergency evolutions are not changed as a result of EPU.

The licensee's response satisfactorily addresses the staff's concerns. The licensee stated that St. Lucie 2 does not credit the fire water pumps or fire protection water supply for non-fire protection functions during normal plant operations. The licensee identified the following two provisions to use other features of the fire protection system for non-fire protection functions: provide makeup water service to the CCW surge tank if the demineralized water system is not available and makeup water to the fuel pool to maintain an adequate fuel pool level in the event loss of the fuel pool cooling system. The staff finds the licensee's response to the RAI acceptable because (1) St. Lucie 2 does not credit the fire water pumps or fire protection water supply for non-fire protection functions during normal plant operations, and (2) the licensee's analysis concluded that the above two functions which use other features of the fire protection system for non-fire protection functions are not affected by the proposed EPU.

Based on the licensee's fire-related safe-shutdown assessment and responses to the RAIs, the staff finds this aspect of the capability of the associated fire protection SSCs to perform their design basis functions at an increased core power level of 3020 MWt acceptable with respect to fire protection.

Conclusion

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

2.5.2 Pressurizer Relief Tank

Regulatory Evaluation

The pressurizer relief tank (PRT), called a quench tank (QT) by the licensee, is a pressure vessel provided to condense and cool the discharge from the pressurizer safety and relief valves. The tank is designed with a capacity to absorb discharge fluid from the pressurizer relief valve during a specified step-load decrease. The QT system is not safety-related and is not designed to accept a continuous discharge from the pressurizer. The NRC staff conducted a review of the QT to ensure that operation of the tank is consistent with transient analyses of related systems at the proposed EPU level, and that failure or malfunction of the QT system will not adversely affect safety-related SSCs. The NRC staff's review focused on any design changes related to the QT and connected piping, and changes related to operational assumptions that are necessary in support of the proposed EPU that are not bounded by previous analyses. In general, the steam condensing capacity of the tank and the tank rupture disk relief capacity should be adequate, taking into consideration the capacity of the pressurizer power-operated relief and safety valves; the piping to the tank should be adequately sized; and systems inside containment should be adequately protected from the effects of high-energy line breaks and moderate-energy line cracks in the pressurizer relief system. The NRC's acceptance criteria for the QT are based on: (1) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes; and (2) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate and be compatible with specified environmental conditions, and be appropriately protected against dynamic effects, including the effects of missiles. Specific review criteria are contained in SRP Section 5.4.11.

Technical Evaluation

In Section 2.5.2 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the QT in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR Section evaluated by the licensee was Section 5.4.11, Quench Tank. The licensee described its historical analysis for the QT ability to condense steam releases without challenging the QT rupture disk for two separate events (the loss of load event and the uncontrolled rod withdrawal event). The licensee calculated that the QT could currently condense 610 pounds of steam for the loss of load event plus 830 pounds of steam for the uncontrolled rod withdrawal event. The license concluded in its assessment that a total mass of 1440 pounds of steam could be successfully condensed without challenging the QT rupture disk for current plant conditions. The licensee used the historical analysis for the QT and its components for comparison to the proposed EPU conditions. The licensee concluded in its evaluation of the QT under EPU conditions that the bounding steam releases for the loss of load event analysis were determined to be 795 pounds of steam and 450 pounds of steam for the uncontrolled rod withdrawal event analysis. Both of the steam releases are less than the design basis mass of 1440 pounds of steam assessed for current plant conditions. The licensee also concluded that no changes to the QT water level or temperature limits were needed since the EPU analysis is bounded by the current historical analysis for the QT.

The staff evaluated the licensee's assessment for the QT according to GDC 2 and GDC 4 and found that no physical changes to the QT and its components are being made to support EPU conditions. The staff also reviewed Review Standard (RS-001) as well as the FSAR for any other potential EPU effects on the QT and found that the QT should support EPU conditions as described above since there are no changes to the QT's design basis. Therefore, the staff concluded that the licensee's QT analysis remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

Conclusion

The staff has reviewed the QT analysis as a result of the proposed EPU and concludes that (1) the QT will operate in a manner consistent with transient analyses of related systems and (2) safety-related SSCs will continue to be protected against failure of the QT consistent with GDC 2 and GDC 4. Therefore, the staff finds the proposed EPU acceptable with respect to the design of the QT.

2.5.3 Fission Product Control

2.5.3.1 Fission Product Control Systems and Structures

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

2.5.3.2 Main Condenser Evacuation System

Regulatory Evaluation

The main condenser evacuation system (MCES), or referred in the St. Lucie 2 FSAR as air evacuation system (AES), generally consists of two subsystems: (1) the "hogging" or startup system that initially establishes main condenser vacuum and (2) the system that maintains condenser vacuum once it has been established. The NRC staff's review focused on modifications to the system that may affect gaseous radioactive material handling and release assumptions, and design features to preclude the possibility of an explosion (if the potential for explosive mixtures exists). The NRC's acceptance criteria for the AES 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 64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs and postulated accidents. Specific review criteria are contained in SRP Section 10.4.2.

Technical Evaluation

In Section 2.5.3.2 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the AES in comparison to its current design basis described in the St. Lucie 2 FSAR. Specific FSAR Section evaluated by the licensee was Section 10.4.2, Air Evacuation System. The licensee determined that the design of the AES does not require modification for the EPU and, therefore, St. Lucie 2 will continue to effectively control radioactive material and monitor radioactive material releases. The licensee also stated that the hogging function is unaffected by uprate because the physical volume of the steam space is not changing and the current steam jet air ejector capacity of 50 cubic feet per minute (cfm) meets these standards for both pre-EPU and EPU conditions. The overall design of the AES will not be changed due to the proposed EPU implementation since the condenser air removal requirements remain within the capacity of the existing system.

The staff reviewed the licensee's assessment of the AES for the effects of the proposed EPU according to GDC 60 and GDC 64. The staff finds the licensee's assessment acceptable since the AES will not be physically changed to continue its current function during EPU conditions and the AES current design being capable of handling EPU operation without any prescribed changes. Therefore, the staff concluded that the licensee's AES analysis remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment of required changes to the MCES and concludes that the licensee has adequately evaluated these changes. The NRC staff concludes that the MCES will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment following implementation of the proposed EPU. The NRC also concludes that the MCES will continue meet the requirements of GDC 60 and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MCES.

2.5.3.3 Turbine Gland Sealing System

Regulatory Evaluation

The turbine gland sealing system is provided to control the release of radioactive material from steam in the turbine to the environment. The NRC staff reviewed changes to the turbine gland sealing system with respect to factors that may affect gaseous radioactive material handling (e.g., source of sealing steam, system interfaces, and potential leakage paths). The NRC's acceptance criteria for the turbine gland sealing system 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 64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs and postulated accidents. Specific review criteria are contained in SRP Section 10.4.3.

Technical Evaluation

In Section 2.5.3.3 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the turbine gland sealing system in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR sections evaluated by the licensee were Section 10.4.3, Turbine Gland Steam System; Section 11.0, Radioactive Waste Management; and 12.3.4, Area Radiation and Airborne Radioactivity Monitoring Instrumentation. The licensee discussed minor effects on the turbine gland sealing system due to the proposed EPU conditions and indicated that mostly all physical components will remain intact except for the increase to the spillover system to support the HP turbine modification and higher HP exhaust pressures due to EPU. The increase is needed to provide sufficient margin to keep the supply zone pressure at acceptable levels. However, the current configuration and functions of the turbine gland sealing system remain unchanged for EPU as related to utilizing the steam from the main steam system, handling pressure from the low pressure turbines, managing increased steam flow and condensate cooling flow, and routing non-condensable gases to the plant vent stack for radioactivity monitoring.

The staff reviewed the licensee's assessment of the turbine gland sealing system for the effects of the proposed EPU according to GDC 60 and GDC 64. The staff finds the licensee's assessment acceptable since the design capacity for controlling the release of radioactive effluents remains unchanged for EPU conditions. The design capacity for the turbine gland sealing system for providing a means to monitor effluent discharge paths and the plant environs for radioactivity also remains unchanged for EPU conditions. Therefore, the staff concluded that the licensee's turbine gland sealing system analysis remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment of required changes to the turbine gland sealing system and concludes that the licensee has adequately evaluated these changes. The NRC staff concludes that the turbine gland sealing system will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment consistent with GDC 60 and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the turbine gland sealing system.

2.5.4 Component Cooling and Decay Heat Removal

2.5.4.1 SFP Cooling and Cleanup System (SFPCCS)

Regulatory Evaluation

The SFP provides wet storage of spent fuel assemblies. The safety function of the SFP cooling and cleanup system is to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. The NRC staff's review for the proposed EPU focused on the effects of the proposed EPU on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions. The NRC's acceptance criteria for the SFP cooling and cleanup system are based on (1) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and (2) GDC 61, insofar as it requires that fuel storage systems be designed with residual heat removal (RHR) capability reflecting the importance to safety of decay heat removal, and measures to prevent a significant loss of fuel storage coolant inventory under accident conditions. Specific review criteria are contained in SRP Section 9.1.3, as supplemented by the guidance provided in Attachment 1 to Matrix 5 of Section 2.1 of RS-001.

Technical Evaluation

In Section 2.5.4.1 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the SFPCCS in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR section evaluated by the licensee was Section 9.1.3, Fuel Pool System. The licensee evaluated the general design basis of SFPCCS, local temperature, SFP bulk temperature, and time-to-boil analyses for the effects of the proposed EPU. The SFPCCS draws warm water from near the surface of the SFP, cools the water, and returns the cooled water to a distribution header low in the SFP. The SFPCCS includes a seismic cooling loop consisting of two cooling pumps and two HXs in a parallel arrangement. The SFPCCS HXs are cooled by CCW.

The licensee provided the following summary of the CLB for the SFPCCS in the licensing report based on information in FSAR Section 9.1.3:

> The cooling portion of the SFPCCS is designed to remove the decay heat produced in the fuel from a full core placed in the SFP 120 hours after reactor shutdown, in addition to the decay heat load from twenty one batches previously

discharged following 18 month fuel cycles. With two fuel pool pumps operating, and with a maximum CCW temperature of 100°F, the maximum SFP water temperature does not exceed 150°F. With one fuel pool pump operating and one fuel pool HX in service and with the maximum CCW temperature of 100°F, the maximum SFP water temperature does not exceed 150°F, when 1883 spent fuel assemblies discharged following > 18 month cycles are in the fuel pool, and the most recent batch of 105 discharged assemblies has cooled for 120 hours. This assumed quantity of stored irradiated fuel exceeds the 1585 assembly licensed storage capacity.

In the licensing report, the licensee described that, for refueling evolutions that involve a full core offload, outage-specific calculations are performed to demonstrate that the SFP bulk water temperature will not exceed the design-basis temperature of 150°F with one fuel pool cooling system pump and one HX in operation.

Operation at EPU conditions would increase the heat load within the SFP. The licensee used the following considerations in evaluating changes to the refueling process to accommodate the greater rate of heat generation:

- Offload time is increased to reduce the impact of the post-EPU decay heat increase on SFP conditions.

- The analyses solved for the maximum offload rate that would maintain bulk pool temperature less than 150 °F.

- More conservative input assumptions were used for the EPU analyses than the pre-EPU analyses.

During EPU conditions, the licensee will utilize administrative guidance developed to control performance of fuel offload evolutions.

The licensee analyzed the following offload scenarios for operation at EPU conditions:

- <u>Scenario 1 - Normal Partial Core Offload</u>

  A partial core offload of 105 limiting assemblies initiated at 140 hours after reactor shutdown, during which the maximum temperature of CCW flow supplied to the SFP HX is conservatively assumed to be 100 °F. All remaining cells of the fuel pool racks were assumed to be filled with conservatively characterized, previously discharged fuel. One fuel pool system cooling pump and one fuel pool HX are assumed to be in service. Various offload rates were analyzed to determine those which would maintain fuel pool bulk temperature 150 °F.

- <u>Scenario 2 - Normal Full Core Fuel Offload</u>

  A full core fuel offload of 217 assemblies having bounding characteristics is discharged into a fuel pool where storage racks are otherwise filled with highly-burned, previously discharged fuel. Two trains of fuel pool cooling (i.e., two fuel pool cooling pumps and two fuel pool HXs) are assumed to be in operation. The offload is initiated at 140 hours after reactor shutdown. The CCW temperature to the fuel pool HXs is assumed to be either 95 °F or 100 °F. Various offload rates were analyzed to determine those which would maintain fuel pool bulk temperature 150 °F.

- <u>Scenario 3 - Full Core Offload, Considering the Failure of a Fuel Pool Cooling Train</u>

  A full core fuel offload into an otherwise filled fuel pool, having conditions and assumptions equivalent to those in Scenario 2, is analyzed to determine the impact of losing one train of fuel pool cooling on the fuel pool temperature rise. The loss of one train of fuel pool cooling is taken at the time of maximum heat load, which is at the end of offload. The calculated temperature increase will be used to set the limit on the maximum pool temperature during offload evolutions, such that a single failure (loss of one fuel pool cooling train) will not result in fuel pool bulk temperature exceeding 150 °F.

For SFP bulk temperature, the licensee's assessment concluded the following:

- For normal partial core offload, the maximum fuel pool bulk temperature calculated for this condition remains < 150 °F considering defueling rates in excess of those physically achievable in the plant, when offload is initiated at ≥ 140 hours after shutdown.

- For normal full core fuel offload, the maximum fuel pool bulk temperature calculated for this condition remains < 150 °F, considering average defueling rates of up to seven assemblies per hour, based on the CCW temperature to the fuel pool HXs being either 95 °F or 100 °F, when offload is initiated at ≥ 140 hours after shutdown.

- For a normal full core offload initiated at 140 hours after reactor shutdown, the licensee determined a maximum thermal overshoot of 27 °F would result from a failure of one of two operating cooling pumps.

The licensee stated that the procedural upper limit for the SFP temperature during full core offloads will be set to ensure that the 150 °F limit would not be exceeded in the event of a failure of one fuel pool cooling pump.

The license's criteria for time-to-boil, as stated in the LAR, utilized the analysis of time-to-boil following an assumed loss of convection for each scenario described above. For the offload scenarios, the licensee applied the following assumptions to ensure the calculated time-to-boil is minimized:

- One assumption constrains the time forced convection is lost to be coincident with the maximum calculated fuel pool bulk temperature.

- Another assumption considers the minimum water volume, with the initial water level in the fuel pool, being no higher than the low level alarm setpoint.

The licensee concluded in the LAR for the time-to-boil analysis that sufficient time would continue to exist under EPU conditions to provide an alternate means of cooling prior to the onset of boiling in the racks. The licensee also determined that the maximum potential makeup requirements for operation at EPU conditions remain well below the available 150 gpm makeup capability. Requirements for inventory makeup, to maintain fuel pool level following the onset of boiling, are within the capability of installed plant systems. The licensee also stated that the SFPCCS piping and valves are acceptable for EPU without changes or modifications. The licensee also evaluated the calculated peak local water temperatures at EPU operating conditions and found that the peak temperature is less than the local saturation temperature for EPU conditions. Thus, no localized boiling occurs and heat transfer with the existing rack design remains adequate.

The staff reviewed the licensee's assessment of the SFPCCS for EPU operation according to GDC 44 and GDC 61. The staff provided RAI SBPB-3, by email dated August 17, 2011, to the licensee regarding clarification of how the procedural upper limit would ensure the pool temperature limit would not be exceeded, considering the committed heat load, once the fuel is placed in the SFP and the large thermal inertia of the pool delaying the indicated temperature relative to peak pool temperature. The licensee provided its RAI response to SBPB-3, by letter, dated October 12, 2011, describing the worst case scenario for the SFPCCS with one SFP cooling train inoperable and the effects of the maximum thermal overshoot temperature of 27 °F. The licensee indicated that the procedural upper limit for the SFP bulk temperature will be set less than 123 °F, so that the maximum bulk temperature, with the failure of one train of SFP cooling, will not exceed 150 °F. The licensee's assessment concluded that the procedural upper limit of 123 °F is acceptable for EPU conditions for maintaining SFP bulk temperature less than or equal to 150 °F due to:

- The rise of SFP temperature of 27 °F is based on a conservative heat load corresponding to assemblies being offloaded at seven assemblies per hour. Also, by using a conservative offload rate of five assemblies per hour, the thermal overshoot decreases by more than 2 °F.

- The SFP heat load assumes SFP being full with all EPU fuel, discharged in the SFP with conservative batch size and schedule, providing additional margin to the thermal overshoot.

- The thermal overshoot of 27 °F accounts for the thermal capacity of the pool in the calculation of the maximum bulk temperature.

The licensee further indicated in its response that the procedural upper limit of 123 °F is expected to be close to the SFP bulk temperature due to:

- The SFP heat load being distributed in the SFP.

- With two trains of SFP cooling in operation prior to the thermal overshoot calculation, there will be sufficient mixing in the SFP when considering the pool configuration with inlet and outlet being on opposite sides of the pool.

- With the SFP bulk temperature rise being on the order of an estimated 1 °F/hr, and taking into account the heat load distribution and coolant movement corresponding to two SFP cooling trains operating, the indicated temperature is expected to remain close to the bulk temperature.

The staff reviewed the licensee's SFPCCS assessment and RAI response and finds the overall assessment acceptable due to the SFPCCS having the continued the capability to handle increased heat loads from safety-related SSCs and handle decay heat removal for EPU conditions. The staff also finds the licensee's establishment of a procedural upper limit of 123 °F for SFP bulk temperature acceptable since it ensures the maximum bulk temperature of 150 °F will not be exceeded in the event of failure of one SFP cooling train. Additionally, the staff finds that the licensee's assessment of the time-to-boil and make-up water requirements remain consistent with the requirements of GDC 61 with respect to preventing a significant reduction in coolant inventory under EPU accident conditions. Therefore, the staff finds the licensee's assessment of the SFPCCS acceptable for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the SFPCCS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the SFP cooling function of the system. Based on this review, the NRC staff concludes that the SFPCCS will continue to provide sufficient cooling capability to cool the SFP following implementation of the proposed EPU and will continue to meet the requirements of GDC 44 and 61. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SFP cooling and cleanup system.

2.5.4.2 Station Service Water System

Regulatory Evaluation

The station service water system (referred to as the intake cooling water (ICW) in the St. Lucie 2 FSAR) provides essential cooling to safety-related equipment through the CCW HX and may also provide cooling to non-safety-related auxiliary components that support normal plant operation. The intake cooling water system is designed to supply sufficient cooling water with a design seawater temperature of 95 °F to the component cooling HXs to fulfill emergency requirements in the event of the DBLOCA. There are no safety-related ICW components or safety-related functions shared between St. Lucie 1 and 2. The ICW system includes two redundant trains and each train is capable of providing the heat removal necessary for mitigation of a DBLOCA. The ICW system pumps, valves, and piping are located outdoors and protection for the system safety function is provided by physical separation of the trains. In addition, the ICW pumps are provided with missile shielding.

The staff's review covered the characteristics of the ICW components with respect to their functional performance as affected by adverse operational (i.e., water hammer) conditions, abnormal operational conditions, and accident conditions (e.g., a LOCA with the LOOP). The staff's review focused on the additional heat load that would result from the proposed EPU. 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, including flow instabilities and loads (e.g., water hammer), maintenance, testing, and postulated accidents; and (2) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.1, as supplemented by GL 89-13 and GL 96-06.

Technical Evaluation

In Section 2.5.4.2 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the ICW in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR section evaluated by the licensee was Section 9.2.1, Intake Cooling Water System. The licensee determined that the ICW system will continue to meet the CLB with respect to the requirements of GDC 4 at EPU conditions. Because the system is located outdoors and its existing design will not be changed to support EPU operations.

The licensee evaluated the following design aspects of the ICW system for operation at EPU conditions:

- ICW flow and heat removal requirements
- Design pressure/temperature of piping and components
- Fouling and tube plugging in HXs cooled by service water

The EPU accident analyses for post-LOCA containment P-T demonstrate that one ICW train provides sufficient heat removal capability to maintain containment parameters within design limits. The staff evaluation of this analysis is provided in Section 2.6.5 of this SE. In Table 2.5.4.2-1 of the EPU licensing report, the licensee also provided a comparison of post-LOCA ICW system response between the EPU containment P-T analysis, which used assumptions minimizing the heat removal from containment, and a similar analysis that used assumptions maximizing the heat transfer to a single train of ICW via the CCW system. Both analyses demonstrated that one ICW train provided sufficient heat removal from the CCW system using a 95°F design inlet temperature such that the ICW temperature at the outlet of the CCW HX remains bounded by the system design temperature of 130 °F.

The licensee stated that the ICW system will also continue to supply sufficient cooling water flow to support safety and non-safety systems, as described in the EPU licensing report, without modifying or creating new operating modes or system lineups. The licensee indicated that there is no change to the ICW pump head performance at EPU conditions. The ICW pumps, design pressure, and temperature do not require modification for EPU and will continue to operate within their design capacity. The ICW outlet temperatures for EPU conditions remain bounded by the design temperature.

The licensee also evaluated the applicability of NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and GL 96-06, "Assurance of Equipment Operability and Containment Integrity during Design-Basis Accident Conditions," to St. Lucie 2 during EPU conditions. In the case of GL 89-13, the EPU will not impact the programs, procedures, and activities in place at St. Lucie 2 and the current routine inspection and maintenance program from GL 89-13 will continue to ensure that the ICW system will remain reliable and operable after EPU implementation. The issues described in GL 96-06 do not apply to the ICW system because system piping does not enter containment,

The staff reviewed the licensee's assessment of the ICW system against GDC 4 and GDC 44 and found that the impact of EPU operation on the systems and components that utilize the ICW will not affect their capabilities to perform their safety functions, especially in the event of accident scenarios such as a LOCA. The current design features of the ICW have been evaluated by the licensee to show that the increased heat removal requirements associated with

EPU remain within the ICW system heat removal capability. The staff found the results of the licensee's assessment reasonable because the changes in ICW system heat removal requirements were dominated by changes in the LOCA energy release, which were small relative to the magnitude of the power uprate.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the ICW and concludes that the licensee has adequately accounted for the increased heat loads on system performance that would result from the proposed EPU. The NRC staff concludes that the ICW will continue to provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU and that the EPU had no effect on the system protection against dynamic effects. Therefore, the NRC staff has determined that the ICW will continue to meet the requirements of GDC 4 and GDC 44. Based on the above, the staff finds the proposed EPU acceptable with respect to the ICW.

2.5.4.3 Reactor Auxiliary Cooling Water Systems

Regulatory Evaluation

The NRC staff's review covered the reactor auxiliary cooling water system (referred to as the CCW system in the St. Lucie 2 FSAR) that is required for (1) safe shutdown during normal operations, AOOs, and mitigating the consequences of accident conditions, or (2) preventing the occurrence of an accident. The CCW system includes closed-loop auxiliary cooling water systems for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the ECCS. The NRC staff's review covered the capability of the CCW system to provide adequate cooling water to safety-related ECCS components and reactor auxiliary equipment for all planned operating conditions. The NRC staff's review focused on the additional heat load that would result from the proposed EPU. The NRC's acceptance criteria for the CCW system is 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 including flow instabilities and attendant loads (i.e., water hammer), maintenance, testing, and postulated accidents and (2) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.2, as supplemented by GL 89-13 and GL 96-06.

Technical Evaluation

In Section 2.5.4.3 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the CCW system in comparison to its current design basis described in the St. Lucie 2 FSAR. The CCW system is described in FSAR Section 9.2.2. The CCW system is designed to remove heat from plant components during all phases of plant operation including startup, power operation, shutdown, refueling and post-accident conditions. The CCW system consists of two HXs, three pumps, one surge tank, a chemical addition tank, and associated piping, valves and instrumentation. The CCW system is arranged into two essential trains and a non-essential header. The non-essential header is automatically isolated from both essential headers by valve closure on a SIAS.

The licensee determined that the CCW system is capable of removing the required EPU heat loads under normal operating, shutdown, and accident conditions with the existing cooling water supply flow rates. The licensee also stated that maximum CCW temperatures will increase after EPU, but will continue to remain within allowable limits, while the time to cooldown the plant will be extended. The licensee determined that the components experiencing an increased heat load at normal plant EPU full power operation are the letdown HX (+0.2 MBtu/hr) and the SFP HX (+1.5 MBtu/hr). The licensee stated that other HXs were evaluated at their design conditions, which remain bounding at EPU.

During normal plant cooldown, the maximum CCW heat load occurs when the SDC system is first placed in service after reactor shutdown. With the higher reactor decay heat at the EPU power level, the heat loads imposed on the CCW system by the SDC HXs would increase to maintain the same cooldown rate. The licensee stated that a dual train cooldown would continue to be utilized and the current administrative cooldown rate limit of 75°F/hr would be maintained. For single train cooldown with minimum CCW flow rates, the licensee stated operators would procedurally control the cooldown rate to less than 75°F/hr in order to maintain the CCW piping temperatures within design limits. Maintenance of this limit with the higher reactor decay heat would lengthen the period to complete a normal cooldown.

As described above in Section 2.5.4.2 for the ICW system, the licensee evaluated DBLOCA heat removal for conditions that maximized containment P-T by minimizing heat removal and maximizing cooling water temperature by maximizing the amount of heat removed via a single CCW train. As evaluated in Section 2.6.5 of this SE, the maximum containment P-T evaluation demonstrated the CCW system would be capable of removing adequate heat for the DBLOCA from EPU operating conditions. The licensee's evaluation of the maximum heat removal by a single CCW train indicated that the existing design piping temperatures would continue to bound accident temperatures in the CCW system.

The licensee evaluated flow considerations for the CCW system. The CCW flow rate does not change at the EPU conditions and no physical changes are being made to the system. There is no change to the CCW pump head performance at EPU conditions and the CCW system operating pressures are not affected by EPU conditions. The CCW system relief valves either have no change or small changes in temperatures that are bounded by the relief valve design. Therefore, the relief valves on the CCW piping at the RCP thermal barrier are unaffected by EPU conditions.

The licensee evaluated application of GL 89-13 to the safety-related CCW HXs cooled by ICW. The licensee concluded that the original responses are not affected by the EPU since the existing procedures and activities in support of GL 89-13 are unaffected and require no changes. The licensee will continue to periodically inspect, test, and maintain the CCW HXs.

The licensee also evaluated the effects of the EPU at St. Lucie 2 on the corrective actions implemented in response to GL 96-06. The licensee stated that the implementation of EPU does not affect the previous corrective actions and responses to GL 96-06. The licensee determined as part of its assessment of GL 96-06 that the small increase in the peak containment post-LOCA temperature at EPU conditions has no impact on the CCW system over pressure protection inside containment. The analysis of containment temperature following a MSLB at EPU conditions indicated that peak temperature would decrease. As part of its actions for GL 96-06, the licensee previously reviewed containment penetrations and installed thermal relief valves on CCW lines subject to over-pressurization. The licensee stated that the EPU condition remains below the system design temperature and pressure and that no additional analysis is required to demonstrate its acceptability.

The staff reviewed the licensee's assessment of the CCW system according to GDC 4 and GDC 44. The staff finds that the EPU will not impact the ability of the CCW system to perform its safety functions at EPU conditions. The staff finds the licensee's assessment acceptable since no physical modifications are required to support EPU operation and the overall CCW system design is capable to handle the minimal increased heat load.

Conclusion

The staff has reviewed the licensee's assessment of the effects of the proposed EPU on the reactor CCW system and concludes that the licensee has adequately accounted for the increased heat loads from the proposed EPU on system performance. The staff concludes that the CCW system will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, the staff has determined that the CCW system will continue to meet the requirements of GDC 4 and GDC 44. Based on the above, the staff finds the proposed EPU acceptable with respect to the CCW system.

2.5.4.4 Ultimate Heat Sink

Regulatory Evaluation

The ultimate heat sink (UHS) is the source of cooling water provided to dissipate reactor decay heat and essential cooling system heat loads after a normal reactor shutdown or a shutdown following an accident. The NRC staff's review focused on the impact that the proposed EPU has on the decay heat removal capability of the UHS. Additionally, the NRC staff's review included evaluation of the design-basis UHS temperature limit determination to confirm that post-licensing data trends (e.g., air and water temperatures, humidity, wind speed, water volume) do not establish more severe conditions than previously assumed. The NRC's acceptance criteria for the UHS are based on (1) 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; and (2) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.5.

Technical Evaluation

In Section 2.5.4.4 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the UHS in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR section evaluated by the licensee was Section 9.2.7, Ultimate Heat Sink. The design basis of the UHS as described in Section 9.2.7 of the FSAR is to: (1) provide sufficient cooling water for safe shutdown of both units or to permit mitigation of a LOCA in one unit and concurrent safe shutdown of the second unit; and (2) to withstand the effects of severe natural phenomena or single failure of a manmade structural feature without a loss of safety function. Plant intake is taken directly from and discharge provided directly to the Atlantic Ocean such that there is no mixing or recirculation of discharge flow. The licensee described that St. Lucie Units 1 and 2 share the UHS. The St. Lucie 2 FSAR described that the primary water source is the Atlantic Ocean via intake pipes to the intake canal, which is used as the source for normal plant operational modes and most accident situations. The secondary source of water is Big Mud Creek, which is connected to the Atlantic Ocean via the Indian River. The intake bay in front of the intake structure is separated from Big Mud Creek by a barrier wall containing two 100 percent flow passages that would be opened following a design basis earthquake that disables the primary intake.

The licensee indicated that no changes to the UHS TS 3/4.7.5 are required for EPU conditions because the UHS would continue provide adequate cooling water to both Units after EPU implementation. The ICW system flow requirements are not changed by EPU and the ICW intake temperatures are consistent with existing UHS temperature limits.

The staff has reviewed the licensee's assessment of the UHS according to GDC 5 and GDC 44 and concludes that the UHS would remain capable of performing its safety functions during EPU operation. No modifications are needed for the UHS to support normal and accident conditions during EPU operation; therefore, the staff finds the licensee's assessment acceptable and no further evaluation of the UHS is needed.

Conclusion

The staff has reviewed the information that was provided by the licensee for addressing the effects that the proposed EPU would have on the UHS safety function, including the licensee's validation of the design-basis UHS temperature limit based on post-licensing data. Based on the information that was provided, the staff concludes that the proposed EPU will not compromise the design-basis safety function of the UHS, and that the UHS will continue to satisfy the requirements of GDC 5 and GDC 44 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the UHS.

2.5.4.5 AFW System

Regulatory Evaluation

In conjunction with a seismic Category I water source, the AFW system (AFWS) functions as an emergency system for the removal of heat from the primary system when the main FW system is not available. The AFWS may also be used to provide decay heat removal necessary for withstanding or coping with an SBO. The NRC staff's review for the proposed EPU focused on the system's continued ability to provide sufficient emergency FW flow at the expected conditions (e.g, SG pressure) to ensure adequate cooling with the increased decay heat. The staff's review also considered the effects of the proposed EPU on the likelihood of creating fluid flow instabilities (e.g., water hammer) during normal plant operation, as well as during upset or accident conditions. The NRC's acceptance criteria for the AFWS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures; (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 19, insofar as it requires that equipment at appropriate locations outside the control room be provided with (a) the capability for prompt hot shutdown of the reactor, and (b) a potential capability for subsequent cold shutdown of the reactor; (4) GDC 34, insofar as it requires that an RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure; and (5) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure. Specific review criteria are contained in SRP Section 10.4.9.

Technical Evaluation

In Section 2.5.4.5 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the AFWS in comparison to its current design basis described in the St. Lucie 2 FSAR. Specific FSAR Sections evaluated by the licensee were Sections 10.5, Auxiliary Feedwater System; 9.2.8, Condensate Storage System; and 15, Accident Analysis.

The AFW system consists of two full-capacity motor driven AFW pumps, one greater-than-full-capacity turbine-driven AFW pump, one condensate storage tank (CST), and associated piping and valves. The licensee described that the AFW system ensures a makeup water supply to the SG secondary side to support decay and sensible heat removal for the reactor core. This heat removal capability allows plant operators to reduce the reactor coolant temperature to entry conditions for SDC. The AFW system normally operates to support plant startup, hot standby, and shutdown evolutions. The CST provides normal source of water for the AFW system with a nominal capacity of 307,000 gallons.

Implementation of the EPU would increase the decay heat removal required to mitigate the various design basis events and, consequently, the makeup water supplied by the AFW system necessary to support that heat removal. The licensee's analysis of the CST analysis indicated that there is sufficient inventory within the CST to provide the required back-up water supply for St. Lucie Unit 1 and enough usable water volume to meet the accident cooldown requirements of St. Lucie 2. The licensee provided extensive details in the EPU licensing report, describing how the current volume in the CST will meet EPU conditions for both St. Lucie 1 and 2. A missile protected inter-tie is provided between the St. Lucie 1 AFW pump suction lines and the St. Lucie 2 CST to be used under administrative control as required by NRC. Check valves prevent inadvertent draining of the St. Lucie 2 CST to the St. Lucie 1 CST. The licensee also indicated that there are no physical modifications to the AFW system required to implement the EPU and that the AFWS will continue to meet the CLB with respect to GDC 5.

The staff reviewed the licensee's assessment of the AFWS for EPU conditions in accordance to GDC 4, GDC 5, GDC 19, GDC 34, and GDC 44. The staff provided RAI SBPB-1, by email dated August 17, 2011, for the licensee to address the assumptions used in the AFWS analysis, boundary conditions, and results of the Loss of Normal FW (LNF) accident analysis. The licensee responded by letter, dated October 12, 2011, that the LNF analysis described in Section 2.5.4.5 of the EPU LAR is an auxiliary analysis performed to assess the AFWS's size for EPU conditions. The LNF event is classified for St. Lucie 2 as an AOO. An AOO has the following acceptance criteria:

- Maximum pressure in the RCS and Main Steam Supply System (MSSS) will be maintained below 110 percent of the design pressure.

- The Specified Acceptable Fuel Design Limits (SAFDLs) are not exceeded, in particular the Departure from Nucleate Boiling Ratio (DNBR).

- The event does not propagate to a more serious event. For the LNF event, long term cooling must be verified by demonstrating the pressurizer does not become water solid. This ensures that a more limiting event is not generated.

The licensee also indicated that the LNF event is bounded by the loss of condenser vacuum event with respect to the RCS and MSSS overpressurization criteria. The licensee also indicated that the LNF event is bounded the loss of forced reactor coolant flow event with respect to SAFDLs and core consequences for the Chapter 15 LNF safety analysis. The licensee concludes its response by indicating that the LNF analysis performed for FSAR Section 10.4.9 at EPU conditions demonstrates that a water solid condition does not result. As part of its response, the licensee provided additional tables and figures to demonstrate how the water solid condition will not occur under EPU conditions for both offsite power events (available and unavailable). The staff has reviewed the licensee's response of the LNF event and has found it acceptable since mitigation measures are currently in place to prevent the LNF event to propagate into a more serious event in limiting the water solid condition.

The staff also provided RAI SBPB-2, by email dated August 17, 2011, so that the licensee could discuss the difference in the flow for the motor driven AFW pump capacity, in which Table 10.4.1, "Component Design Parameters," of Amendment 19 of the St. Lucie 2 FSAR lists the flow for the AFW pumps as 300 gpm versus the delivered flow of 320 gpm to the entrance of the SGs as provided in Attachment 4 of the LAR. The licensee responded to RAI SBPB-2, by letter dated October 12, 2011, that the capacity of 300 gpm in Table 10.4-1 of the St. Lucie 2 FSAR is based on the original sizing for the AFW pumps as demonstrated by the manufacturer's pump curve. The licensee's assessment of the AFW pumps using this curve concluded that the motor driven AFW pumps are capable of supplying 320 gpm to the entrance of the SGs at 1000 psia as stated in the Bases for TS 3/4.7.1.2. The EPU accident analysis input for AFW flow is 275 gpm per motor driven pump to a SG at 1000 psia. The licensee further indicated that the motor-driven AFW pumps, as provided in plant procedures, are tested at a flow of 246 gpm which, as required by the ASME code, is within ± 20 percent of the 300 gpm full flow rate identified in FSAR Table 10.4-1. The staff reviewed the licensee's response and found it acceptable since the AFW pumps are tested in accordance with the ASME Code to ensure the capability to deliver the required AFW flow to the SGs at EPU operating conditions.

The licensee evaluated other operating parameters and capabilities related to the AFW system, including design P-T of piping and components, net positive suction head (NPSH), flow rates to support normal startup and shutdown, containment isolation, and AFW actuation. The licensee concluded that these operating parameters and capabilities would be unaffected by the EPU. The staff reviewed the operating parameters and system capabilities against proposed modifications and changes associated with operation at EPU conditions, and the staff agreed that the identified operating parameters and capabilities would be unaffected by the EPU because the limiting operating conditions would not change as a result of operation at EPU conditions. The staff finds that the licensee's assessment of the AWFS will continue to meet the requirements of GDC 4, GDC 5, GDC 19, GDC 34, and GDC 44 for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the AFWS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in decay heat and other changes in plant conditions on the ability of the AFWS to supply adequate water to the SGs to ensure adequate cooling of the core. The NRC staff finds that the AFWS will continue meet its design functions following implementation of the proposed EPU. The NRC staff further concludes that the AFWS will continue to meet the requirements of GDC 4, 5, 19, 34, and 44. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the AFWS.

2.5.5 Balance-of-Plant Systems

2.5.5.1 Main Steam

Regulatory Evaluation

The MSSS transports steam from the NSSS to the power conversion system and various safety-related and non-safety-related auxiliaries. The NRC staff's review focused on the effects of the proposed EPU on the system's capability to transport steam to the power conversion system, provide heat sink capacity, supply steam to drive safety system pumps, and withstand adverse dynamic loads (e.g., water steam hammer resulting from rapid valve closure and relief valve fluid discharge loads). The NRC's acceptance criteria for the MSSS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures; (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, insofar as it requires that an RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core. Specific review criteria are contained in SRP Section 10.3.

Technical Evaluation

In Section 2.5.5.1 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the MSSS in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR Section evaluated by the licensee was Section 10.3, Main Steam Supply System. The licensee made the following determinations for the MSSS during EPU conditions:

Piping Design Pressure-Temperature

The licensee indicated that the MSSS design P-T of 985 psig (1000 psia) and 550 °F bound the maximum EPU operating conditions and that the no load conditions are unaffected by the EPU.

Piping Flow Velocities

The licensee indicated that the main steam velocities at current and EPU conditions are bounded by the industry design guidelines velocity, with the exception of two areas. But these areas will not have a significant impact on the MSSS component materials because of the steam's low water content.

Component Design Pressure-Temperature

As described above under Piping Evaluations, Design P-T, the main steam design P-T are not affected by the EPU. The design conditions of the main steam components were reviewed and determined to be greater than the EPU operating conditions.

Main Steam Safety Valves Capacities and Setpoints

The licensee indicated that the MSSVs setpoints will remain unchanged for EPU. The licensee stated that the current MSSVs are acceptable at EPU condition without physical modification. However, the licensee proposed changing the setpoint tolerance of the MSSVs specified in TS 3/4.7.1.1 for operational flexibility. The TS required MSSV setpoints are currently 1000 psia +1/-3 percent (8 valves) and 1040 psia +1/-3 percent (8 valves). The licensee proposed changing the tolerance to ±3 percent for the MSSVs with the lower setpoint and +2 percent/-3 percent for the MSSVs with the higher setpoint. The licensee stated that this tolerance change has been factored into the plant's accident analyses, which the staff evaluated in Section 2.8.5 of this SE. The proposed change to the TS 3/4.7.1.1 MSSVs setpoint tolerance is acceptable because the change is consistent with the assumptions of the limiting accident analyses.

Atmospheric Dump Valves (ADVs)

The licensee indicated that the performance of the ADVs is acceptable at EPU conditions with no plant changes required to satisfy the decay heat removal requirements in accordance with the CLB requirements with respect to GDC 34. The steam release from the ADVs would be unchanged at EPU operating conditions because the valve design and the no-load SG pressure are unchanged. The licensee evaluated the capability of the ADVs to support plant cool down at the maximum required rate at EPU conditions and found the cool down performance acceptable. The staff evaluation of the cool down analysis is provided in Section 2.8.7.2 of this SE.

Main Steam Isolation Valves

The licensee indicated that the MSIVs current design pressures and temperatures are valid for EPU conditions since they are equal to the piping design pressure and design temperature. Closing times of the MSIVs are unaffected at EPU conditions because the design of the valve is such that pressure on either side of the valve has no effect on valve closure time due to the fact that it is operated by a fail-closed spring-loaded actuator. The licensee's assessment of the MSIVs concluded that they will continue to close within their current maximum stroke time of 5.6 seconds under EPU conditions. The MSIVs were found to be bounded by the original stress analysis and therefore acceptable at EPU conditions. The licensee concluded for the MSIVs that the factors of erosion, vibration, DP, and flow turbulence were acceptable at EPU conditions.

Turbine Stop, Control, and Reheat Stop and Intercept Valves

The licensee indicated that the HP turbine stop valves have been evaluated as being acceptable for EPU. The HP turbine control valves were evaluated by the licensee and are physically adequate for operation at EPU. The low pressure turbine reheats stop and intercept valves have also been evaluated and are adequate for EPU operation.

Auxiliary Main Steam Supply Flow Rates

The MSSS supplies steam to the following auxiliary loads:

- Moisture separator reheaters (MSR)
- AFW pump turbine
- Auxiliary steam system
- Priming ejector
- Turbine gland sealing steam system

The licensee indicated that the MSRs are being replaced for EPU and are designed for the uprated steam flows. The MSSS will continue to supply the required steam flow to the MSRs at EPU. The licensee found the AFW pump turbine supply and exhaust piping to be acceptable for EPU conditions due to the pressure ratings of piping and valves remaining bounded at its current analysis. The licensee also stated that the MSSS will continue to supply steam to auxiliary components, including the turbine gland steam supply and the condenser air ejectors, and will not be affected by the EPU.

Main Steam Piping Drain Capacity

The licensee indicated the MSSS piping drains are acceptable for EPU operation despite minor changes in steam P-T. This is due to the drain flow not being significantly affected.

The staff reviewed the licensee's assessment of the MSSS according to GDC 4 and GDC 5 and did not find any implications that would allow the MSSS system to negatively impact the SSCs important to safety at EPU conditions. The current analysis for normal and accident scenarios remain unchanged for EPU conditions and minimal modifications to the MSSS system are needed to support EPU operation. Therefore, the staff finds the licensee assessment of the MSSS acceptable for EPU operation.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the MSSS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MSSS. The evaluation of the accident analyses in Section 2.8.5 and the analysis of natural circulation cool down in Section 2.8.7.2 provide reasonable assurance that the MSSVs and ADVs retain sufficient capacity to remove residual heat at the required rate to satisfy GDC 34. The NRC staff concludes that the MSSS will maintain its ability to relieve steam to the atmosphere for residual heat removal, transport steam to the power conversion system, supply steam to the auxiliary components, and continue to perform its functions at EPU conditions. The staff further concludes that the MSSS will continue to meet the requirements of GDC 4 and GDC 5. Therefore, the staff finds the proposed EPU acceptable with respect to the MSSS.

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, which is referred to as the steam bypass control system (SBCS) for St. Lucie 2. The NRC staff's review of the main condenser for proposed power uprates focuses primarily on the impact that an EPU will have on the control of radiological releases to the environment. For PWRs, the effect of the proposed EPU on the concentration of radionuclides in the condenser is negligible because leakage from the RCS through the SG to the main steam system is limited. The licensee determined that the condenser would maintain structural integrity during operation because it satisfactorily removes the increased EPU heat loads, condenses the required steam flows, and maintains an acceptable vacuum using circulating water at the current normal operating flow rate. Therefore, the main condenser will continue to control the release of radioactive material that may be introduced to the main condenser and a detailed evaluation is not necessary.

2.5.5.3 Turbine Bypass

Regulatory Evaluation

The SBCS is designed to discharge a stated percentage of rated main steam flow directly to the main condenser system, bypassing the turbine. This steam bypass enables the plant to take step load reductions up to the SBCS capacity without the reactor or turbine tripping. The system is also used during startup and shutdown to control SG pressure. The staff's review focused on the effects that EPU has on load rejection capability, analysis of postulated system piping failures, and on the consequences of inadvertent SBCS operation. The NRC's acceptance criteria for the TBS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures; and (2) GDC 34, insofar as it requires that an RHR system is provided 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. Specific review criteria are contained in SRP Section 10.4.4.

Technical Evaluation

In Section 2.5.5.3 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the SBCS in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR section evaluated by the licensee was Section 10.4.4, Steam Dump and Bypass System. The licensee provided a brief description of the SBCS and indicated that the SBCS piping design pressure of 985 psig (1000 psia) bounds the actuation setpoint pressure of 900 psia, which remains unchanged for EPU conditions. The licensee stated that a modification to the SBCS is being performed such that the system will be able to pass the greater rated steam flow for EPU operation. The modification will ensure that the system continues to comply with the CLB requirements with respect to both the protection against dynamic effects (GDC 4) and the ability to provide a means for shutting down the plant during normal operations to reduce the demands on systems important to safety (GDC 34).

The staff evaluated the licensee's assessment of the SBCS according to GDC 4 and GDC 34 and found that the system modifications to the SBCS to support EPU conditions will have a minimal impact on the functionality of the SBCS. The staff also finds that the SBCS capability to handle steam bypass from the turbine will remain unchanged for EPU conditions. The staff finds the licensee's assessment of the SBCS acceptable.

Conclusion

The staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SBCS. The staff concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the system. The staff further concludes that SBCS failures will not adversely affect essential systems or components. Based on this, the staff concludes that the SBCS will continue to meet GDC 4 and GDC 34. Therefore, the staff finds the proposed EPU acceptable with respect to the SBCS.

2.5.5.4 Condensate and FW

Regulatory Evaluation

The condensate and FW system (CFS) provides FW at the appropriate temperature, pressure, and flow rate to the SGs. The only part of the CFS classified as safety-related is the FW piping from the SGs up to and including the outermost containment isolation valve. The NRC staff's review focused on the effects of the proposed EPU on previous analyses and considerations with respect to the capability of the CFS to supply adequate FW during plant operation and shutdown, and to isolate components, subsystems, and piping in order to preserve the system's safety function. The NRC staff's review also considered the effects of the proposed EPU on the FW system, including the AFWS piping entering the SG, with regard to possible fluid flow instabilities (e.g., water hammer) during normal plant operation, as well as during upset or accident conditions. The NRC's acceptance criteria for the CFS 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; (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 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure. Specific review criteria are contained in SRP Section 10.4.7.

Technical Evaluation

In Section 2.5.5.4 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the CFS in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR section evaluated by the licensee was Section 10.4.6, Condensate and Feedwater System. The licensee made the following assessments of the CFS:

Design Pressures and Temperatures – Components and Piping

The licensee indicated that current design pressures and temperatures of CFS components and piping bound the EPU operating conditions with the exception of the design temperature of the main FW pump recirculation valves. However, the valve body materials were evaluated by the licensee and determined to be acceptable for a range of temperatures which bound the maximum EPU operating temperatures.

FW Heaters

The licensee indicated that FW heaters and external drain coolers were acceptable for EPU conditions with the exception of the high pressure 5A/B FW heaters. The design and construction of the existing 1A/B through 4A/B FW heaters was evaluated by the vendor and found acceptable for operation at EPU conditions with specific monitoring measures in place to evaluate the potential for long term degradation. The 5A/B FW heaters are being replaced with new high pressure (HP) FW heaters designed for EPU conditions. The replacement HP FW heaters 5A/B will be supplied with new relief valves designed to meet the EPU conditions. The replacement HP FW heaters 5A/B will be supplied with new venting orifices designed to meet the EPU conditions. The standards contained in Heat Exchange Institute (HEI) Standards for FW Heaters along with the manufacturer's standards were used for acceptance criteria for the evaluation of the existing FW heaters. The licensee determined that the new FW heaters will meet the thermal performance requirements of the EPU conditions. The FW heaters shell and tube side design pressures and temperatures bound the EPU operating conditions. The licensee also stated that the existing relief valve capacities and setpoints are acceptable for EPU operation since the design pressures are not changing.

Flow Velocities – Piping

The licensee indicated that the flow velocities through the CFS will remain below the industry standard guidelines at EPU conditions. The licensee will not replace the condensate pump suction piping for EPU conditions since the licensee's assessment indicate that the current piping can withstand the increased flow velocities from the proposed EPU operation. The licensee will install Leading edge flow meters (LEFMs) as part of EPU implementation which will enhance FW flow measurement. Thermowells also extend into the flow steam and are used throughout the CFS for temperature measurement. The EPU velocities are bounded by the maximum velocities for which the thermowells are designed.

FW Regulating Valves

The licensee indicated that the existing FW regulating valves will be modified to provide the required flow at the required pressure drop at EPU conditions. The valve modifications will allow the valves to utilize approximately 80 percent of the valves' rated flow coefficient during normal plant operation at EPU so as to provide sufficient control over a range of operating conditions and provide additional margin for transients. The licensee iterated that the EPU is not changing the function or monitoring features of the FW regulating valves.

Condensate and FW Pumps and Supporting Subsystems

The licensee discussed several changes in the EPU licensing report to the CFS pumps and supporting systems for support of EPU operation. These changes do not impact any safety-related systems and are being made to increase efficiency of the CFS system in power generation.

FW Isolation Valves

The licensee indicated that the MFIVs were evaluated for the increased flow rates, DPs, and temperatures at EPU. The MFIVs will continue to meet the existing required closure times at the EPU conditions. The licensee also stated that the containment isolation requirements are unaffected by EPU and the current plant design features remain acceptable.

The staff evaluated the licensee's assessment of the CFS according to GDC 4, GDC 5, and GDC 44 and found that the EPU operation will not prevent the CFS from performing its normal and transient functions, provided that the licensee make the evaluated changes to the CFS equipment prior to EPU implementation. The modifications to the CFS do not prevent the system from withstanding a water hammer or lead to the failure of SSCs important to safety. St. Lucie 2 also will maintain its isolation capacity to preserve the system safety function. The staff finds the licensee's assessment of the CFS acceptable for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the CFS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the CFS. The NRC staff concludes that the CFS will continue to maintain its ability to satisfy FW requirements for normal operation and shutdown, withstand water hammer, maintain isolation capability in order to preserve the system safety function, and not cause failure of safety-related SSCs. The NRC staff further concludes that the CFS will continue to meet the requirements of GDC 4, 5, and 44. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CFS.

2.5.6 Waste Management Systems

2.5.6.1 Gaseous Waste Management Systems

Regulatory Evaluation

Gaseous waste management systems (GWMSs) involve the gaseous radwaste system, which deals with the management of radioactive gases collected in the offgas system or the waste gas storage and decay tanks. In addition, it involves the management of the condenser air removal system, the SG blowdown flash tank, and the containment purge exhausts; and the building ventilation system exhausts. The staff's review focused on the effects that the proposed EPU may have on (1) the design criteria of the GWMSs, (2) methods of treatment, (3) expected releases, (4) principal parameters used in calculating the releases of radioactive materials in gaseous effluents, and (5) design features for precluding the possibility of an explosion if the potential for explosive mixtures exist. The NRC's acceptance criteria for the GWMS are based on (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC 3, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (4) GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (5) 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" (ALARA) criterion. Specific review criteria are contained in SRP Section 11.3.

Technical Evaluation

The licensee's evaluation of the impact that EPU 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 St. Lucie 2 EPU licensing report. The licensee determined that the EPU will result in a slight increase in the equilibrium radioactivity in the reactor coolant, which results in an increased concentration of radioactive nuclides in the radioactive waste system. The licensee found that the existing GWMS will remain capable of processing this increase in radioactive nuclide concentration. The proposed EPU activities would not add any new components to the GWMS, nor would they introduce any new functions for existing components. Operating experience confirms the small effect of EPUs on radioactive gas production.

Radiological and environmental monitoring of the waste streams is not affected by the proposed EPU and no new or different radiological release paths will be introduced. However, the proposed EPU will result in an increase in the activity associated with gaseous radioactive waste and, therefore, potential radiological releases and offsite doses will be impacted. The licensee determined that the estimated doses resulting from radioactive effluents following implementation of the EPU would remain a small percentage of allowable Appendix I doses. The licensee's evaluations of potential releases under accident and normal operating conditions are reviewed in Sections 2.9 and 2.10 of this SE, respectively.

Section 11.3 of the St. Lucie 2 FSAR describes that the oxygen content in the WGMS is continuously monitored to prevent development of a potentially explosive gas mixture. The monitoring is performed in accordance with TS 3.11.2.5, "Explosive Gas Mixture." The licensee also has measures in place, as described in FSAR Section 13.7.1.5, to purge cover gas containing high levels of oxygen to the gaseous waste system with nitrogen gas, thereby diluting the oxygen concentration. The staff determined these measures to control the potential development of explosive gas mixtures are unaffected by the proposed EPU.

Based on a review of the information that was submitted, the staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the GWMS to perform its functions. Because the increase in radioactive gas generation would be insignificant, the staff agrees that the capabilities of the GWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the GWMSs. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of gaseous waste on the abilities of the systems to control releases of radioactive materials and preclude the possibility of an explosion if the potential for explosive mixtures exists. The NRC staff finds that the GWMSs will continue to meet their design functions following implementation of the proposed EPU. The NRC staff further concludes that the GWMSs will continue to meet the requirements of 10 CFR 20.1302, GDC 3, 60, and 61, and 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the GWMSs.

2.5.6.2 Liquid Waste Management Systems

Regulatory Evaluation

The staff's review for liquid waste management systems (LWMS) focused on the effects that the proposed EPU may have on previous analyses and considerations related to the liquid waste management systems' design, design objectives, design criteria, methods of treatment, expected releases, and principal parameters used in calculating the releases of radioactive materials in liquid effluents. The NRC's acceptance criteria for the LWMS are based on (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (4) 10 CFR Part 50, Appendix I, Sections II.A and II.D, which set numerical guides for dose design objectives and LCOs to meet the ALARA criterion. Specific review criteria are contained in SRP Section 11.2.

Technical Evaluation

The licensee provided its evaluation of the EPU impact on the capability of the LWMS to collect and process liquid radioactive waste in Section 2.5.6.2 of the St. Lucie 2 EPU licensing report. The licensee determined that the proposed EPU conditions will have minimal effect on the volumes of radioactive waste generated; however, it will change the radioactivity content of the waste. The proposed EPU would not change the collection, segregation, processing, discharging or recycling of radioactive liquid wastes. Also, the proposed EPU would not change any of the sources of potentially contaminated leakage or create any new flow paths which would allow for the contamination of systems designed for uncontaminated liquids. The licensee determined that the estimated doses resulting from radioactive effluents following implementation of the EPU would remain a small percentage of allowable Appendix I doses. The methodology used to determine the effect of the change in radioactivity content in liquid waste is addressed in Section 2.10 of this SE.

Based on a review of the information that was submitted, the staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the LWMS to perform its functions. Because the increase in offsite dose will be relatively small and the doses will remain a small fraction of the allowable Appendix I doses, the staff agrees that the capabilities of the LWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the LWMS. The staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of liquid waste on the ability of the LWMS to control releases of radioactive materials. The staff finds that the LWMS will continue to meet their design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the LWMS will continue to meet the requirements of 10 CFR 20.1302, GDC 60 and 61, and 10 CFR Part 50, Appendix I, Sections II.A and II.D. Therefore, the staff finds the proposed EPU acceptable with respect to the LWMS.

2.5.6.3 Solid Waste Management Systems

Solid radioactive waste consists of wet and dry waste. Wet waste consists mostly of low specific activity spent secondary and primary resins and filters, and oil and sludge from various contaminated systems. The NRC staff's review relates primarily to the wet waste dewatering and liquid collection processes, and focuses on the impact that the proposed power uprate will have on the release of radioactive material to the environment via gaseous and liquid effluents. Because this is a subset of the evaluations performed in Sections 2.5.6.1 and 2.5.6.2 of this SE, a separate evaluation of solid waste management systems is not required.

2.5.7 Additional Considerations

2.5.7.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

Regulatory Evaluation

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions (e.g., power diesel engine-driven generator sets), assuming a single failure. The NRC staff's review focused 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 NRC's acceptance criteria for the emergency diesel engine fuel oil storage and transfer system are based on (1) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects, including missiles, pipe whip, and jet impingement forces associated with pipe breaks; (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 17, insofar as it requires onsite power supplies to have sufficient independence and redundancy to perform their safety functions, assuming a single failure. Specific review criteria are contained in SRP Section 9.5.4.

Technical Evaluation

In Section 2.5.7.1 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the EDG fuel oil storage and transfer system in comparison to its current design basis described in the St. Lucie 2 FSAR. The specific FSAR section evaluated by the licensee was Section 9.5.4, Diesel Generator Fuel Oil System. The licensee assessed the fuel oil inventory and consumption rate along with the EDG loading analysis following LOOP events for the proposed EPU conditions. The licensee indicated that the fuel consumption rates of the

EDGs allow the maximum usable volume of the fuel oil storage system to run one each EDG for at least 7 days for their required post-LOCA loads. As stated in the FSAR, the total capacity of one fuel oil storage tank is required to support the EDG run time. The licensee concluded that no modifications are needed for the EDGs or EDG fuel oil system to support EPU conditions. The licensee proposed a change to TS 3.8.1.1, which increases the minimum fuel storage system requirement for each EDG set from 40,000 gallons to 42,500 gallons. The licensee stated that the change is required to capture the additional volume of ultra low sulfur fuel oil because of its lower energy content.

The staff has reviewed the licensee's assessment of the EDG fuel oil storage and transfer system according to GDC 4, GDC 5, and GDC 17 and found that the system has the capability to perform its safety functions for EPU operation. The staff finds the change to TS 3.8.1.1 acceptable since the TS change is related to the characteristics of the fuel oil being used for EPU operation, and it is not impacting the current design analysis to be able to handle emergency power loads following a LOOP event. The licensee has indicated that the current EDG fuel oil inventory is capable of operation during EPU conditions, and the staff finds the increase of fuel oil volume in the TS 3.8.1.1 to have a negligible effect on EPU operation. Therefore, the staff finds the licensee assessment of the EDG fuel oil storage and transfer system acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the amount of required fuel oil for the EDGs and concludes that the licensee has adequately accounted for the effects of the increased electrical demand on fuel oil consumption. The NRC staff concludes that the fuel oil storage and transfer system will continue to provide an adequate amount of fuel oil to allow the diesel generators to meet the onsite power requirements of GDC 4, 5, and 17. The staff also finds the proposed changes to TS 3.8.1.1 acceptable due to the change being related to accounting for the additional volume of ultra low sulfur fuel oil needed to support EPU operation. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel oil storage and transfer system.

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, handling of new and irradiated fuel within the SFP and refueling cavity, and loading spent fuel into shipping casks. Because the licensee proposed no modifications to fuel handling equipment and the post-EPU fuel would be mechanically the same as the pre-EPU fuel, this area of review is not affected by the proposed power uprate and an evaluation of the LLHS is not required.

2.6 Containment Review Considerations

2.6.1 Primary Containment Functional Design

Regulatory Evaluation

The St. Lucie 2 containment is a right circular cylinder with a hemispherical dome that encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. While operating at EPU condition, and following a DBLOCA or an MSLB accident, the peak containment internal pressure and its wall temperature must remain below the internal design pressure and the structural design temperature. The containment maximum internal design pressure is 44 psig, and the structural design temperature is 264 °F.

The NRC staff's review covered the P-T 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 P-T conditions resulting from any LOCA; (3) GDC 38, insofar as it requires that the containment heat removal system(s) function to rapidly reduce the containment P-T 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.

Technical Evaluation

LOCA Containment Analysis

The licensee performed containment P-T response analysis to demonstrate that the peak P-T meet the SRP acceptance criteria and the containment heat removal system is acceptable for mitigation of the consequences of a DBLOCA inside the containment under EPU conditions.

The licensee used the current version of NRC-approved CONTRANS (Reference 25) computer code methodology for LOCA containment performance analyses. The CONTRANS topical report (Reference 25) provides the description of the analytical techniques, governing equations, and solution methods. Section 6.2.1.1.3 of St. Lucie 2 FSAR describes the changes and/or enhancements in the current version of the CONTRANS computer code.

The licensee listed conservative inputs and assumptions that differed from the CLB inputs and assumptions including those in which conservatism was increased.

The M&E release analysis for calculating the LOCA containment P-T response is evaluated in Section 2.6.3.1 of this report. The licensee analyzed double-ended discharge leg slot break, double-ended suction leg slot break, and double-ended hot leg slot (DEHLS) break LOCA cases with different single failure scenarios. The limiting case that gave the highest peak P-T is the DEHLS break. For the limiting case, the calculated peak pressure was 43.48 psig and a pressure of 6.36 psig at 24 hours. The containment design pressure is 44 psig and the acceptance criteria includes allowing the containment leakage rate to decrease by 50 percent after 24 hours if the containment pressure is shown to decrease below 50 percent of the calculated peak pressure within 24 hours. Therefore the SRP acceptance criteria for both peak pressure being less than the design pressure and the pressure at 24 hours less than 50 percent of the calculated peak pressure is met. For the same DEHLS break case, the licensee calculated a peak containment vapor temperature of 266.73 °F, which exceeds the containment vessel design temperature of 264 °F for approximately 30 seconds. However, for this case, the calculated peak containment vessel temperature is 231.64 °F, which is well below the containment vessel design temperature of 264 °F. The NRC staff agrees with the licensee that the calculated maximum containment vessel temperature under EPU conditions for LOCA event is less than its design temperature with sufficient margin.

For EPU, the licensee proposed to revise the 10 CFR Part 50 Appendix J TS containment integrated leakage rate test pressure (P_a) from 41.8 psig to 43.48 psig. The NRC staff agrees with the licensee because the proposed value of P_a is consistent with the calculated peak pressure for the limiting DBLOCA.

MSLB Containment Analysis

The licensee performed MSLB containment analyses to calculate the containment P-T response by considering the break of the main steam line at the SG outlet nozzle, upstream of the MSIVs. The licensee states that this break results in the maximum possible steam flow for a given break size. The licensee states that the break flow would be limited to that from one SG because of closure of MSIVs associated with each SG. For conservatism, the licensee analyzed all cases of containment P-T response with offsite power available because a LOOP results in a reduction of reactor coolant flow, reduces the energy transfer to the secondary side thus reducing the energy release to the containment and resulting in lesser P-T response.

The evaluation of MSLB M&E release analysis is given in Section 2.6.3.2 of this report. The licensee used NRC-approved computer code SGNIII as in the current analysis for M&E release analysis and simultaneously calculated the P-T response obtained from the integrated module from the NRC-approved CONTRANS computer code (Reference 25). The licensee has combined the CONTRANS code for containment response and the SGNIII code for M&E release to run them together. For a given time step, the M&E release data generated by SGNIII code is fed to the CONTRANS code, which calculates the containment P-T for that time step. The containment temperature and pressure is subsequently fed back to the SGNIII and the M&E release rates for the next time step are generated. The licensee has maintained the name SGNIII for the integrated code.

The licensee listed conservative inputs and assumptions (Reference 26) that differed from the CLB inputs and assumptions including those in which conservatism was increased. The licensee took credit for the operation of two fan coolers in the analysis. Regarding the conservatisms in the SGNIII code, the licensee states that it can over-predict the restart power. The EPU analysis limited the restart power to 15 percent, which provides significant margin over the peak restart value generated in the MSLB reactor safety analysis, but not as high as it would go due to the SGNIII code and conservative assumptions that are part of the containment MSLB methodology.

For the peak pressure analysis, the licensee used the following conservative inputs (Reference 26) to obtain a limiting (higher) pressure response: (a) used the maximum initial containment pressure, (b) did not consider superheating upon SG U-tube uncovery which is conservative for the containment pressure response, (c) did not consider re-evaporation of the heat sink condensate. The most limiting single active failure was determined to be the failure of one containment cooling train. The licensee determined that the limiting case that resulted in the maximum peak containment pressure was at zero percent thermal power. The peak pressure calculated for this case is 42.41 psig, which is below the design limit of 44 psig.

For the EQ analysis, the licensee used the following inputs (Reference 26) to obtain a limiting peak temperature response: (a) used the minimum initial containment pressure to delay the reactor trip which maximizes the M&E release to the containment, (b) used a superheat model in which the steam in the SG shell side is allowed to superheat as the tubes uncover, and (c) assumed re-vaporization of the condensate, as permitted by NUREG-0588 Appendix B, Section 1.b, which allows 8 percent of the condensation that collects on the heat sink walls to evaporate. The most limiting single active failure was determined to be the failure of the MSIV to close. The licensee determined that the limiting case that resulted in the maximum peak containment temperature was at 100.3 percent thermal power. The licensee calculated the peak containment vapor temperature to be 384.29 °F which is less than the CLB peak EQ temperature of 418.3 °F. In an RAI the licensee was requested to provide reasons for the lower EPU peak EQ peak temperature than the CLB peak EQ temperature. In its response the licensee states that the replacement SGs nozzle flow restrictors have reduced the break size, reducing the mass of steam released into the containment before the operation of CS system and therefore resulting in a lower EQ peak temperature. The licensee also states that the reduction in the EPU peak temperature was also due to tighter control of the SGNIII restart power. The EPU peak containment vapor temperature of 384.29 °F exceeds the containment vessel design temperature of 264 °F for approximately two (2) minutes. However during this period the licensee's calculated containment vessel temperature is 244.8 °F, which is less than the containment vessel design temperature of 264 °F.

The NRC staff considers the licensee's evaluation of the MSLB containment analysis acceptable because it used NRC-approved methodology and computer codes with conservative inputs and assumptions.

The licensee evaluated the containment under EPU conditions for license renewal and determined that there are no new aging effects that require management and no changes are necessary to any existing AMPs. The licensee states that EPU does not add any new or previously unevaluated materials, or introduce any new system or component functions nor does it change the functions of existing components that would affect the system boundaries for license renewal.

Conclusion

The NRC staff has reviewed the licensee's assessment of the containment P-T transient and concludes that the licensee has adequately accounted for the increase of M&E that would result from the proposed EPU. The staff further concludes that containment systems will continue to provide sufficient P-T 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, 16, 38, 50, and 64 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to containment functional design.

2.6.2 Subcompartment Analyses

Regulatory Evaluation

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The NRC staff's review for subcompartment analyses covered the determination of the design DP values for containment subcompartments. The NRC staff's review focused on the effects of the increase in M&E release into the containment due to operation at EPU conditions, and the resulting increase in pressurization. The NRC's acceptance criteria for subcompartment analyses are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects, and (2) GDC 50, insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments. Specific review criteria are contained in SRP Section 6.2.1.2.

Technical Evaluation

The NRC staff evaluation of the containment subcompartment analysis consists of evaluation of P-T response of reactor cavity, shield wall, and pressurizer subcompartments due to postulated line breaks under EPU conditions. As per St. Lucie 2 FSAR, the LBB methodology is applicable to St. Lucie 2 selected piping. As a result, compartment pressurization and dynamic effects associated with circumferential (guillotine) breaks in the reactor cavity and shield wall, and longitudinal (slot) break of the suction side of cold leg piping in the shield wall is no longer considered a licensing basis. Section 2.6.3 of this report presents the SE of the postulated accidents M&E release analysis results that were used as an input for the subcompartment P-T response.

For the reactor cavity, the NRC staff agrees with the licensee that based on NRC staff approval of the application of LBB methodology, and as in the CLB, subcompartment analysis for the reactor cavity area is not required to be addressed for EPU conditions.

The secondary shield wall design DP is 24 psid. The licensee states that a suction leg guillotine break at the SG nozzle is the limiting break that has the largest M&E releases, and produces the highest DP in the secondary shield wall subcompartment. The CLB DP for the secondary shield wall from the results of the above break is 5.9 psid, which represents a 307-percent margin from the design DP. The CLB M&E release from this break bounds all M&E releases from the smaller RCS line breaks including the main steam line double ended break under the EPU condition. The licensee states that M&E release for a suction leg guillotine break for the CLB bounds the M&E release from the same break under the EPU conditions. In an RAI the licensee was requested to explain why the M&E release for a pump suction leg guillotine break for the CLB bounds the M&E release under the EPU conditions. In its response (Reference 26), the licensee states that the application of the LBB criteria has eliminated the need to evaluate the pump suction leg guillotine break under EPU conditions. The secondary shield wall is designed to withstand a DP resulting from the CLB pump suction leg guillotine break. Therefore under EPU conditions, the secondary shield wall sub-compartment DP resulting from smaller breaks is bounded by the CLB design DP. The NRC staff agrees with the licensee's evaluations and therefore the current design margin remains unchanged.

The pressurizer cavity is divided into upper cavity and lower cavity. The upper cavity is affected by the pressurizer relief line break, pressurizer spray line break, and the pressurizer surge line break. For the lower pressurizer cavity, the limiting break is the surge line break.

The upper pressurizer cavity is designed for a DP of 14 psid. As per the evaluation given in Section 2.6.3.1 of this report, the M&E release due to a guillotine break in the pressurizer relief line, under the EPU conditions is unchanged from the CLB. Therefore the pressure response of the upper cavity due to relief line break is unaffected under EPU conditions. As per evaluation given in Section 2.6.3.1 of this report, the EPU mass release rate from the pressurizer spray line break is less than 2 percent greater than its current value, and the energy release rate is less than one percent greater than its current value, at the lowest analyzed EPU cold leg temperature of 543 °F. Also as per evaluation given in Section 2.6.3.1 of this report, the EPU mass release rate from the pressurizer surge line break is less than 0.8 percent greater than its current value, and the energy release rate is less than 0.4 percent greater than its current value, at the lowest analyzed EPU cold leg temperature of 543 °F. The licensee states that relative to compartment pressure response, the small increases in the M&E releases are compensated due to an increase in the vent area of approximately 190 square feet with the removal of missile shield roof of the pressurizer cavity, which was not considered in the CLB design analyses (refer to FSAR Section 6.2.1.2.3.c). The licensee, therefore, concludes, and the NRC staff agrees with the licensee that the design margin for the upper pressurizer cavity wall structure may be conservatively assumed to remain unchanged under the EPU conditions.

The lower pressurizer cavity is designed for a DP of 24 psid which is the same as design DP of the shield wall subcompartment because it is open to the shield wall subcompartment. Section 2.6.3.1 of this report provides an evaluation of the M&E release due to a break in the surge line, which is 0.8 percent and 0.4 percent higher than their CLB values of M&E respectively at the lowest analyzed cold leg temperature of 543 °F under EPU conditions. The licensee states that it is conservative to assume that the pressure increase is proportional to the M&E release increase. Therefore the maximum DP of the lower pressurizer cavity is conservatively estimated as approximately 22.7 psid at the EPU conditions, which is 0.8 percent higher than its current value of 22.5 psid. The licensee concluded that the design margin for the lower pressurizer cavity is approximately 6 percent under EPU conditions. The NRC staff agrees with licensee's evaluation.

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 difference across the walls following implementation of the proposed EPU. Based on this, the NRC staff concludes that the plant will continue to meet GDC 4 and 50 for the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to subcompartment analyses.

2.6.3 M&E Release

2.6.3.1 M&E Release Analysis for Postulated Loss of Coolant

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.

Technical Evaluation

LOCA M&E Release for Long Term Containment P-T Response

The licensee performed the EPU LOCA M&E releases using the current methodology documented in FSAR Section 6.2.1.3. The LOCA containment P-T response analysis initiated with the reactor operating at 100 percent EPU plus 2-percent measurement uncertainty, consists of four phases: (a) blowdown, (b) reflood, (c) post-reflood, and (d) long term cooldown phase. The licensee conservatively biased the energy release rate to the containment by assuming the heat transfer from the core to the reactor coolant to be always in the nucleate boiling regime. As a result, the cladding temperature remains low enough that its oxidation due to the metal-water reaction is insignificant. Therefore, the contribution to the energy release rate from the metal-water reaction is negligible and was not included in the M&E analysis. The NRC staff considers this acceptable because the sensible heat transferred from the core to the reactor coolant is maximized in the nucleate boiling regime. The licensee simulated the blowdown phase of the LOCA using the NRC-approved CEFLASH-4A code (Reference 27) using biased inputs to conservatively calculate the M&E release during this phase. The reflood and post-reflood phases of the LOCA are simulated using the FLOOD3Mod2 computer code, which is an extension of the NRC-approved FLOODMOD2 code (Reference 28), used in the CLB analysis. For cold leg breaks the effect of the SGs on the M&E discharged into the containment is important after the blowdown because the exiting steam passes through the SGs acquiring more energy prior to release to the containment. For the hot leg break, the licensee did not simulate the reflood and post-reflood phases because the break flow does not pass through the SGs prior to release to the containment. For the long term cooldown phase, the licensee used the current version of NRC-approved CONTRANS (Reference 25) computer code methodology for the LOCA containment performance analyses. The long term analysis considers all residual energy in the primary and secondary systems and decay heat.

In an RAI the licensee was requested to describe the impact of a code error in CEFLASH-4A identified by Westinghouse in calculating the M&E release and the containment P-T response. In its response (Reference 29) the licensee states that CEFLASH-4A/FII code error referred to in the RAI was actually an input deficiency. Analyses performed in the early 1990s used a print interval for tables of M&E that was too coarse to capture the peak values of M&E releases in the first half-second of RCS blowdown for a large break LOCA (LBLOCA). Consequently, a large amount of M&E released in the containment on an integrated basis was not accounted for in the containment response portion of the analysis and, therefore, containment peak P-T were under predicted. This code input deficiency was identified prior to completion of the proposed EPU analysis. The proposed EPU analysis used a fine print interval to generate the M&E table and confirmed that the peak values of M&E calculated in the CEFLASH-4A/FII code were used in the containment response analysis. The NRC staff finds the licensee's response acceptable.

The NRC staff considers the M&E release analysis for LOCA acceptable because the licensee used conservative inputs and assumptions, used NRC-approved methodologies, and considered all sources of energy as well as the limiting break size and location as per SRP Section 6.2.1.3.

LOCA M&E Release for Short Term Subcompartment Analysis

The NRC has approved LBB methodology for St. Lucie 2. According to the LBB methodology, RCS piping determined not to catastrophically rupture does not have to be considered for subcompartment analyses. Therefore as in the CLB, reactor cavity pressurization is not considered as a licensing basis under EPU conditions.

The licensee performed a short-term LOCA M&E release evaluation for the pressurizer compartment by considering breaks in the pressurizer relief line, pressurizer spray line, and in the surge line. For a conservative short term M&E release calculation the licensee used bounding inputs with measurement uncertainties, assuming (a) minimum core inlet temperature including uncertainty, (b) maximum reactor coolant flow rate with uncertainty, (b) nominal full reactor power with uncertainty and pump heat. The licensee followed the guidance given in SRP, Section 6.2.1.3, M&E Release Analysis for Postulated Loss-of-Coolant Accidents Subsection II, Part 3a to perform the calculation. The licensee used Henry-Fauske correlation that conservatively models the M&E release which is directly related to the critical break mass flux at sub-cooled condition.

The M&E release from the three postulated breaks is evaluated in the following paragraphs.

The licensee states that for the guillotine break in the pressurizer relief line, the short term M&E release that depends only on the initial pressurizer pressure is unaffected because the initial pressurizer pressure under the EPU conditions is unchanged from the pressure in the CLB.

The licensee states that the guillotine break in the pressurizer spray line will release M&E from the pressurizer side as well as the cold leg side. The M&E release from the cold leg side of a pressurizer spray line break is dependent only on the initial pressure and enthalpy in the pumps discharge side of the cold leg. The licensee's evaluation showed that, as the cold leg temperature decreases, the M&E release rates would increase. For a guillotine break in the pressurizer spray line, the licensee determined that at the lowest initial cold leg temperature of 543 °F, the highest initial release of mass flux is less than 2 percent greater, and the highest initial release of energy flux is less than 1 percent greater compared to their respective highest release rates at the CLB conditions.

The licensee states that for a pressurizer surge line guillotine break at the EPU conditions, the limiting mass release is 0.8 percent greater and the energy release 0.4 percent greater than the CLB conditions.

The NRC staff considers the evaluation of the short term M&E release into the pressurizer subcompartment analysis acceptable because the licensee used conservative inputs and assumptions.

The short term evaluation of the pressurizer subcompartment P-T response is given in Section 2.6.2 of this SE report.

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 EPU and appropriately accounts for the sources of energy identified in 10 CFR Part 50, Appendix K. Based on this, the NRC staff finds that the M&E release analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative. Therefore, the NRC staff finds the proposed EPU acceptable with respect to M&E release for postulated LOCA.

2.6.3.2 M&E Release Analysis for Secondary System Pipe Ruptures

Regulatory Evaluation

The NRC staff's review covered the energy sources that are available for release to the containment, the 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.

Technical Evaluation

The licensee performed M&E release analysis for steam line break inside containment for several cases at various power levels ranging from hot zero to 100-percent reactor power plus measurement uncertainty, and different single failure assumptions. The licensee used NRC-approved computer code SGNIII, which was also used in the current analysis. The licensee listed and justified differences in the major inputs and assumptions between the CLB and the EPU analysis. The analysis and acceptance criteria followed guidance provided in SRP Section 6.2.1.4. Additionally the licensee evaluated a LOOP accident case and confirmed that it is bounded by the non-LOOP cases. The NRC staff accepts the licensee's M&E evaluation because the licensee used the same computer code as in the CLB and with justified inputs and assumptions.

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 addresses the effects of the proposed EPU. Based on this, the NRC staff concludes that the analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative (i.e., that the analysis includes sufficient margin). Therefore, the NRC staff finds the proposed EPU acceptable with respect to M&E release for postulated secondary system pipe ruptures.

2.6.4 Combustible Gas Control in Containment

Regulatory Evaluation

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

Technical Evaluation

The licensee submitted an LAR by letter dated June 4, 2007, requesting revision in TS requirements associated with hydrogen recombiners and hydrogen monitors in accordance with a September 16, 2003, revision to 10 CFR 50.44. The NRC staff approved the LAR by letter dated February 22, 2008 (Reference 30), which removed hydrogen recombiners from the TS, and reclassified the monitoring system from safety-related to non-safety-related consistent with RG 1.97. Regarding the containment atmosphere mixing following a DBA, and the capability of monitoring hydrogen concentration beyond DBA, the licensee states that these are not impacted by EPU and will remain as described in the FSAR. The NRC staff agrees that under EPU conditions, St. Lucie 2 will continue to satisfy the requirements of 10 CFR 50.44.

The licensee evaluated the combustible gas control system under EPU conditions for licensee renewal and determined that there are no new aging effects that require management and no changes are necessary to any existing AMPs. The licensee states that the EPU does not add any new or previously unevaluated materials, or introduce any new system or component functions nor does it change the functions of existing components that would affect the system boundaries for license renewal.

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, 41, 42, and 43 as discussed above.

Therefore, the NRC staff finds the proposed EPU acceptable with respect to combustible gas control in containment.

2.6.5 Containment Heat Removal

Regulatory Evaluation

Containment heat removal systems that consist of the spray system, fan cooler system and SDC system are provided to remove heat from the containment atmosphere and from the water in the containment sump. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the available NPSH to the containment heat removal system pumps and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler HXs. The NRC's acceptance criteria for containment heat removal are based on GDC 38, insofar as it requires that the containment heat removal system be capable of rapidly reducing the containment P-T 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, Rev. 3.

Technical Evaluation

The containment heat removal system removes heat from the containment following a LOCA, or a secondary system line break in order to limit the containment P-T below the design conditions. The system consists of two separate ESF systems, which are the CS system and the containment cooling system. The CS system consists of two redundant trains, each with a CS pump, SDC HX and CS header. During the recirculation phase, the CS system takes suction from the containment sump and directs flow through the SDC HXs and sprays water into the containment through the spray header. The containment cooling system consists of four containment fan cooler (CFC) units. The licensee states that one CS pump and two CFC units have the capacity to reduce the containment P-T following a DBA and maintain them at acceptably low levels.

The EPU would increase the heat load on the containment heat removal system. The licensee performed containment integrity analysis by analyzing three LOCA cases under EPU conditions with different single failure scenarios as described in Section 2.6.1 of this report. As described in Section 2.6.1 of this report, the licensee performed the MSLB containment analysis to calculate the containment P-T response by considering the break of the main steam line at the SG outlet nozzle, upstream of the MSIVs. The licensee used minimum CS pump flow rates for the injection and recirculation mode for the above analyses. For the heat removal capacity of the SDC HX the licensee used the current design values during the recirculation mode. For the CFCs which are powered by the EDGs, the licensee adjusted their design heat removal rate conservatively by considering the under-frequency operation of the EDGs during accident conditions. The above analyses demonstrated that the current CS system and containment cooling system will limit the containment peak pressure and containment wall temperature below the design limits of 44 psig at 264 °F under EPU conditions. Section 2.6.1 of this report covers the SE of the containment integrity analysis. The NRC staff considers the licensee's evaluation of the containment heat removal systems for LOCA and MSLB accident mitigation acceptable because the licensee used NRC-approved methodology and computer codes with conservative inputs and assumptions.

The licensee states that it followed the RG 1.1, Revision 0 to perform the NPSH calculations for the ECCS and CS pumps operating during recirculation mode using the maximum sump fluid temperature and the containment pressure before the accident.

In an RAI the licensee was requested to provide a summary of the NPSH analyses at the EPU conditions, including assumptions for the NPSH required (NPSHR), consideration of crediting containment accident pressure, and the conservatisms in calculating NPSH available (NPSHA). In its response (Reference 26), the licensee described the analysis under EPU conditions which determined that adequate NPSH margin is available during the injection and recirculation modes for the CS and ECCS pumps. The licensee states that the calculations have demonstrated that throughout the recirculation mode duration, the containment sump water temperature never exceeds 200 °F. The licensee assumed the most limiting single active failure and used conservative inputs and assumptions to minimize the NPSHA during the safety injection and recirculation modes. Assuming the NPSHR based on the ‘3 percent head drop’ Hydraulic Institute (HI) standard definition, the licensee showed that the available NPSH for the CS, and ECCS pumps exceeds the required NPSH by more than 68 percent in the safety injection mode (Reference 26), and by more than 27 percent (Reference 26) in the recirculation mode. The licensee did not take credit for the containment accident pressure to determine the NPSHA during the recirculation mode. The NRC staff considers the NPSH analysis acceptable because the licensee used conservative assumptions to minimize the NPSHA, showed adequate margin between the NPSHA and the ‘3 percent head drop’ HI standard values of NPSHR, while not using the available containment accident pressure under EPU conditions.

In an RAI the licensee was requested to provide a discussion of how the post-accident debris generation is affected by the EPU, and describe its impact on the response to GL 2004-02 related to the resolution of Generic Safety Issue (GSI)-191. The licensee was also requested to describe the impact of EPU on the sump strainer head loss and on the pump NPSH evaluations during post-LOCA operation of the ECCS and CS pumps. In its response (Reference 26) the licensee states that EPU has no effect on the post-accident debris generation because the zone of influence used in calculating the debris generation radii is independent of the RCS operating P-T. The zone of influence is only affected by the inside diameter of the broken pipe and the insulation type, which is not being changed for EPU. The flow rates of the ECCS and CS pumps are not a function of RCS operating parameters or the post-LOCA decay heat rates and, therefore, not affected by the EPU. The sump strainer head loss values are a function of sump flow rate, temperature and debris loading. The licensee selected the recirculation flow rates used in the EPU NPSH calculations conservatively greater than the GSI-191 sump design flow rates. The licensee’s EPU NPSH calculations also include consideration of the GSI-191 sump screen head losses. The head losses determined by the GSI-191 are adjusted to reflect the EPU NPSH calculation flow rates and sump water temperatures. This sump strainer head loss values used in the EPU NPSH analyses are, therefore, conservative. The NRC staff accepts the licensee’s response to NRC staff RAI regarding the impact of EPU on the response to GL 2004-02.

The licensee evaluated the EPU impact on the response to GL 96-06. This GL states: “Thermally 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 states that the small increase (4.5 ^{o}F approximately) in the containment peak post-LOCA temperature at EPU conditions has no impact on the over-pressure protection of the CCW system piping that supplies cooling water to the CFC. Also the MSLB accident has no impact on the CCW lines penetrating containment because there is a decrease in containment temperature (34 °F approximately) following a MSLB at the EPU conditions. The NRC staff considers the licensee's re-evaluation of the GL 96-06 for the CCW system piping design temperature that penetrate the containment supplying the CFCs acceptable because the small increase in the post-LOCA containment peak temperature is bounded by the CLB CCW system piping design temperature.

The licensee evaluated the containment heat removal systems under EPU conditions for licensee renewal and determined that there are no new aging effects that require management and no changes are necessary to any existing AMPs. The licensee states that the EPU does not add any new or previously unevaluated materials, or introduce any new system or component functions nor does it change the functions of existing components that would affect the system boundaries for license renewal.

Conclusion

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

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

Changes affecting NPSH margin due to the EPU do not affect GSI-191 open issues. Therefore the proposed EPU is acceptable with respect to GSI-191.

2.6.6 Pressure Analysis for ECCS Performance Capability

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.

Technical Evaluation

As specified in 10 CFR 50.46, Appendix K, paragraph I.D.2, the containment pressure used for the evaluation of the effectiveness of ECCS during the re-flood and spray cooling shall not exceed the containment pressure calculated conservatively for this purpose. To support the implementation of EPU, the licensee performed the minimum containment pressure analysis for the ECCS performance evaluation using the NRC staff approved 1999 evaluation model (1999 EM) version of the Westinghouse LBLOCA evaluation model for CE designed PWRs (Reference 31). This model is consistent with the CLB in which the licensee used the CEFLASH-4A (Reference 27) computer code to determine the LOCA blowdown phase M&E release to the containment, and the COMPERC-II computer code to determine the reflood phase M&E release to the containment and the minimum containment pressure response to be used in the evaluation of the effectiveness of the ECCS. The licensee calculated the minimum containment pressure response conservatively by including the effects of operation of all installed systems and processes that reduce the pressure inside the containment.

In an RAI, the licensee was requested to provide a comparison of inputs and assumptions made in the EPU basis with the CLB and justify those inputs and assumptions that are less conservative in the EPU basis. In its response the licensee states that there are no changes in assumptions made in the CLB analysis for the EPU LBLOCA ECCS performance analysis. The licensee listed the input differences between the CLB and EPU analysis and states that none of the inputs for EPU analysis are less conservative than those of the CLB analysis.

In an RAI the licensee was requested to state which of the guidance given in BTP 6-2, Revision 3, "Minimum Containment Pressure Model for PWR ECCS Performance Evaluation," was not used in setting the containment model input parameters and provide justification for not using the conservative guidance. In its response the licensee states that all applicable guidance in BTP 6-2 Revision 3 was used in setting the containment model input parameters.

The NRC staff considers the licensee's analysis acceptable because the licensee used conservative inputs and assumptions, and as required in Appendix K of 10 CFR Part 50, the containment pressure transient used in the calculation of peak cladding temperature is bounded by the minimum containment pressure response during the post-LOCA reflood phase.

The licensee evaluated the containment under EPU conditions for licensee renewal and determined that there are no new aging effects that require management and no changes are necessary to any existing AMPs. The licensee states that EPU does not add any new or previously unevaluated materials, or introduce any new system or component functions nor does it change the functions of existing components that would affect the system boundaries for license renewal. The NRC staff accepts that the pressure analysis the EPU does not impact any license renewal evaluations.

Conclusion

The NRC staff has assessed the impact that the proposed EPU would have on the minimum containment pressure analysis and concludes that the impact has been adequately addressed to ensure that St. Lucie 2 will continue to meet its CLB with respect to the requirements in 10 CFR 50.46 regarding ECCS performance following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to minimum containment pressure analysis for ECCS performance.

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

The NRC staff reviewed the control room habitability system and control building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. A further objective of the NRC staff's review was to ensure that the control room 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 EPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination. The NRC's acceptance criteria for the control room habitability system are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with postulated accidents, including the effects of the release of toxic gases; and (2) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 Roentgen equivalent man (rem) whole body, or its equivalent, to any part of the body, for the duration of the accident. Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of RS-001.

Technical Evaluation

The licensee evaluated the effects of the EPU on the control room habitability systems during normal and emergency operation and states that the EPU would not cause any significant changes to the control room envelope integrity, equipment heat loads internal to the control room, heating and cooling capacity of the ventilation system to maintain the ambient temperatures required for personnel comfort and equipment operability, filtration of airborne contaminants and maintaining positive static pressure during emergency operation.

There licensee states that no modifications are performed for the EPU that would significantly increase the equipment heat loads internal to the control room in comparison to the overall load and equipment capacity. Section 2.7.3.1 below provides an evaluation of the control room ventilation system to provide cooling to the control room under the EPU conditions. The licensee also states that the EPU will not introduce any toxic material hazards to the control room operators.

Conclusion

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

2.7.2 Engineered Safety Feature Atmosphere Cleanup

Regulatory Evaluation

ESF atmosphere cleanup systems are designed for fission product removal in post-accident environments. These systems generally include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., emergency or post-accident air-cleaning systems) for the FHB, control room, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed EPU 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 control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident; (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.

Technical Evaluation

The systems that are included in the ESF atmosphere cleanup systems are: (1) CS system, (2) SBVS, (3) ECCS area ventilation system and (4) control room emergency cleanup system. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed EPU on the system design for normal and emergency operation.

The CS system removes post accident heat and fission products from the containment atmosphere following a postulated accident. The licensee states that the EPU does not affect the CS to reduce the iodine release in the containment.

During LOCA conditions, the SBVS mixes the outside air leakage into the shield building with the air in the annulus and any post-accident fission products leakage from the containment and filters it through charcoal adsorbers prior to release to the outside atmosphere. Following an accident, the system limits the pressure rise and also maintains a negative pressure in the shield building annulus. The shield building annulus is designed for an internal-to-external DP of 3 psi and also an external-to-internal DP of 3 psi. The licensee states that the EPU does not change any of the SBVS components, air flow rates or associated controls. The EPU affects the post-accident containment P-T transients, and the shield building annulus transients. Under the EPU conditions the shield building annulus pressure reaches a peak of 4.9 inches of water gage, which is an increase from the CLB pressure of 3.5 inches of water gage, but remains bounded by the design pressure. The licensee states that the time to establish a negative pressure in the annulus decreases from 310 seconds to 282 seconds for the EPU, which is bounded by the 310 seconds assumed in the dose analyses. The licensee states that the reasons for these differences are: (a) the post-LOCA increased containment P-T at the EPU conditions, (b) SBVS fan performance at 1 percent EDG under frequency, (c) revised computer modeling from WA-TEMPT code in the CLB to generation of thermal hydraulic information for containments (GOTHIC) code for the EPU, and (d) the inclusion of the radiation heating of the air, which was considered negligible in the CLB analysis. The licensee evaluated the affect of the EPU on the charcoal adsorber temperature and determined that the cooling air flow at its minimum value of 300 cfm is sufficient to maintain the adsorber temperature below its alarm setpoint of 200 °F. Therefore, the shield building annulus design parameters (maximum DP and time to reach negative pressure) remain valid for EPU. The licensee also states that the ability of the SBVS to reduce the concentration and quantity of post-accident fission products released from the containment to the environment is not affected by the EPU and is in compliance with GDC 41, as demonstrated in licensing report Section 2.9.2

The ECCS area ventilation system provides post-LOCA filtration and adsorption of fission products in the exhaust air from areas of the RAB that contain safety-related equipment. The system maintains a slightly negative pressure in the ECCS area with respect to the atmosphere. The licensee states that the ECCS area ventilation system charcoal filters are not impacted by the EPU because their maximum temperature rise is well below the ignition temperature or the iodine de-adsorption temperature.

The control room emergency cleanup system captures and retains airborne particulates and adsorbs radioactive iodine, which may be present in the control room supply air during accident conditions. The licensee states that under the EPU conditions there is no significant increase in either radiation levels or contamination levels that would affect the ability of the control room emergency cleanup system to maintain control room dose levels and permit continuous occupation of the control room in compliance with GDC 19. During the post-accident conditions, the airborne fission products that reach the control room charcoal filters originate from filtered releases from the SBVS and unfiltered containment bypass leakage both diluted with outside air. The licensee states that the net fission products from these two sources are less than that which is used to calculate the SBVS filter adsorber inventory. The licensee estimated the maximum temperature rise in the charcoal adsorber is approximately 1 °F, which after adding to the control room temperature of 81 °F results in an adsorber temperature well below the ignition temperature. The application of alternate source term (AST) methodology resulted in reduced iodine inventory and associated heat load in the charcoal filters to less than that predicted to have been accumulated in the TID-14844 design basis analysis. Although the proposed power uprate will increase the source term, the resulting iodine inventory and associated heat load in the charcoal filters will still remain below the design basis TID-14844 values. Therefore the maximum temperature rise and the iodine loading will be much smaller when compared to that of the SBVS filters addressing both the impact of the AST and EPU.

Conclusion

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

2.7.3 Ventilation Systems

2.7.3.1 Control Room Area Ventilation System (CRAVS)

Regulatory Evaluation

The function of the CRAVS is to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components during normal operation, AOOs, and DBA conditions. The NRC's review of the CRAVS focused on the effects that the proposed EPU 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 CRAVS 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 control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident; 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.

Technical Evaluation

The CRAVS maintains control room temperature and humidity for personnel comfort during normal conditions, limit control room dose due to airborne activity to within GDC 19 limits during post-accident conditions, permit personnel occupancy inside the control room during toxic gas release accident, and permit personnel occupancy and equipment functioning during normal and post-accident conditions assuming a single failure. Regarding changes in the control room equipment for the EPU, the licensee proposes to replace the existing computer with a modern computer with a lesser heat load. Also the licensee proposes to add the new Cameron Leading Edge Flow Meter CheckPlus™ system computer in the control room which has an insignificant affect on the heat load. The licensee states that there are no other EPU modifications that would increase the equipment heat loads internal to the control room in comparison to the overall load and equipment capacity, and the temperatures of the areas surrounding the control room do not significantly change. For the above changes, the licensee determined that the proposed EPU has no effect during normal, abnormal, or emergency conditions on the ability of the CRAVSs to provide a controlled environment for the comfort of control room personnel and to support the operability of the control room components. Regarding toxic gas, the licensee states that implementation of the EPU does not impose any new threat to the control room from toxic gas, or smoke. The licensee states that the maximum temperature of the CCW that removes heat from the ventilation equipment is being increased from 108 ^{o}F to 120 ^{o}F. In an RAI, the licensee was requested to describe the reasons for increasing the CCW supply temperature, and also provide an evaluation of the control room air conditioning (CRAC) equipment in order to be able to maintain the required temperature and humidity while operating at the increased CCW supply temperature. In it response (Reference 26) the licensee states that the maximum CCW supply temperature is increased to 120 ^{o}F during hot shutdown and accident conditions because of the increased decay heat under EPU conditions. Based on the CCW supply temperature of 120 ^{o}F, the licensee states that the existing CRAC units are being modified by replacing the refrigerant, compressors and drive motors, ASME certified condensers, evaporator coils, and equipment controls. The licensee states that with the CRAC units modification, the same control room indoor design condition as in the CLB will be maintained. The NRC staff considers the licensee's evaluation of the CRAVS acceptable because the modified system will maintain the same control room indoor design conditions under EPU conditions as in the CLB.

The EPU evaluation and compliance with GDC 19 regarding adequate radiation protection of control room personnel under accident conditions is provided in Section 2.7.1.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components. The 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 EPU, and associated changes to parameters affecting environmental conditions for control room personnel and equipment. Accordingly, the NRC staff concludes that the CRAVS will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed EPU. The 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, 19, and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CRAVS.

2.7.4 SFP Area Ventilation System

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 FHAs. The NRC staff's review focused on the effects of the proposed EPU 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.

Technical Evaluation

The spent fuel handling area ventilation system ventilates the SFP cooling equipment contained within the FHB. The system also reduces personnel doses by preventing the accumulation of airborne radioactivity. The system HEPA and charcoal filters captures and retain airborne particulates and adsorbs radioactive elemental iodine, which may be present in the FHB atmosphere due to diffusion of fission products from the SFP. The licensee states that the decay heat in the SFP will increase under EPU conditions, however the maximum SFP water temperature during normal EPU operation and refueling operation under EPU conditions remains below the current design temperature of 150 °F. The licensee states there are no additional heat sources introduced for the EPU in the SFP building and the ambient outside conditions remains the same as in the CLB. The fuel pool and the building ambient design temperatures are not affected by the EPU. Based on this, the licensee concluded that the existing FHB ventilation system will maintain the required temperature conditions for personnel and equipment during EPU operation. In an RAI the licensee was requested to provide an evaluation of the effect of loss of SFP cooling on the FHB ventilation system. In its response (Reference 26), the licensee states that during a loss of SFP cooling, the temperature of the area will follow the temperature of the pool water because of the heat transfer from the pool water to the surrounding area. The licensee also states that the SFP pumps and HXs areas are ventilated by separate ventilation systems that are not affected by the EPU. The NRC staff accepts licensee's evaluation because the SFP design temperature is unaffected by the EPU and, therefore, the SFPAVS will maintain the required temperature conditions for personnel and equipment during EPU operation. The licensee also states that the ability of the system to reduce plant personnel doses due to potential airborne activity resulting from diffusion of fission products from the SFP water is not impacted because the air distribution, exhaust airflow rates and patterns, and filtration do not change with EPU.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SFPAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's capability to maintain ventilation in the 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 NRC staff concludes that the SFPAVS will continue to meet the requirements of GDC 60 and 61. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SFPAVS.

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

Regulatory Evaluation

The function of the auxiliary and radwaste area ventilation system (ARAVS) and the turbine area ventilation system (TAVS) is to maintain ventilation in the auxiliary and radwaste equipment and turbine areas, permit personnel access, and control the concentration of airborne radioactive material in these areas during normal operation, during AOOs, and after postulated accidents. The NRC staff's review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of these systems. The NRC's acceptance criteria for the ARAVS and TAVS are based on GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4.

Technical Evaluation

The RAB ventilation systems consist of the following subsystems: (a) RAB main ventilation system, (b) RAB electrical equipment and battery room ventilation system, and (c) RAB miscellaneous ventilation systems. The RAB main ventilation system supplies air to the ECCS pump rooms, SDC HX rooms, penetration areas and nonessential areas of the RAB. RAB electrical equipment and battery room ventilation system provides ventilation to the electrical equipment rooms and battery rooms. The RAB miscellaneous ventilation systems provide ventilation to various areas of the RAB. Radiological cold and hot locker room personnel areas are provided with local air conditioning units and exhaust fans. The radwaste area is located inside the RAB and is serviced by the RAB main ventilation system. The turbine building is an open structure with no mechanical ventilation system for the equipment areas except for the switchgear room and chemical storage areas, which are enclosed. Equipment in open areas is ventilated by natural ventilation. Because the chemical storage area is not impacted by the EPU, its ventilation is not discussed further. The turbine building ventilation is not required to mitigate the consequences of a DBA or provide safe shutdown of the reactor, therefore it is not designed to safety or seismic requirements.

The licensee evaluated the RAB ventilation systems and the turbine building ventilation system and determined that EPU does not result in additional heat sources added to the areas served by the systems because no additional equipment or batteries are added to areas served by the RAB ventilation systems during normal operation. Since no additional batteries are being added, the EPU does not change the requirements for maintaining hydrogen concentrations in the RAB from the CLB. The licensee states that EPU does not affect maintaining space pressurization and control of airborne radioactive effluents during normal and emergency conditions. The licensee also states that EPU does not change the ability of the RAB ventilation systems to move air from areas of low potential radioactivity to areas of higher potential radioactivity and filter the air from rooms within the RAB that may contain radioactivity. EPU does not alter the supply or exhaust air flow paths, air flow rates, filtration, or ability to isolate any portion of the RAB ventilation systems. Refer to Section 2.7.6, engineered safety feature ventilation system for evaluation of ventilation to the ECCS area during accident conditions. Regarding the turbine switchgear room ventilation system, the licensee states that the proposed EPU modifications will increase the load current for some of the existing motors without any change in the connected horsepower rating. The increase is less than 1 percent of the existing total nameplate motor ratings supplied by the switchgear and load centers in the turbine switchgear room. In an RAI the licensee was requested to explain why this increase does not significantly impact the heat load and the turbine switchgear room ventilation system. In its response (Reference 26) the licensee states that the existing ventilation system can accommodate this small increase and will still have 11.6 percent margin under the EPU conditions. The NRC staff considers the licensee's evaluation of the RAB ventilation systems acceptable because the licensee demonstrated that a significant margin exists under the EPU conditions.

Conclusion

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

2.7.6 Engineered Safety Feature Ventilation System

The following ESF ventilation systems are evaluated in the Sections given below:

- Control Room Habitability – Refer to Section 2.7.1 for SE
- Engineered Safety Feature Atmosphere Cleanup - Refer to Section 2.7.2 for SE
- Control Room Ventilation System - Refer to Section 2.7.3 for SE
- Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems - Refer to Section 2.7.5 for SE
- Other Ventilation Systems (Containment) - Refer to Section 2.7.7 for SE

The following ESF ventilation systems are evaluated in this Section:

- ECCS Area Ventilation
- EDG Building Ventilation
- Intake Structure Ventilation System
- Component Cooling Area Ventilation System

Regulatory Evaluation

The function of the engineered safety feature ventilation system (ESFVS) is to provide a suitable and controlled environment for ESF components following certain anticipated transients and DBAs. The NRC staff's review for the ESFVS focused on the effects of the proposed EPU 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.

Technical Evaluation

The ECCS area ventilation system provides post accident filtration and adsorption of fission products in the exhaust air from areas of the RAB which contain safety-related equipment. Two ECCS area ventilation system exhaust monitors measure the airborne effluent from the ECCS area. The system maintains a slightly negative pressure in the ECCS area with respect to surrounding areas of the RAB. EPU does not change the requirements for filtering the air from ECCS areas within the RAB that may contain fission products. EPU does not alter the supply or exhaust air flow paths, air flow rates, filtration, or ability to isolate any portion of the ECCS. There are no changes in the operation of the ECCS system or RAB structure, which could affect pressurization of the ECCS areas as a result of the EPU. No additional equipment heat gains were added by the EPU to areas served by the ECCS area ventilation system. Any increases in piping or transmission heat gains at EPU are within the capability of the existing system. There is no change to seismic classification to SSCs within the RAB.

The EDG building ventilation system provides environmental conditions suitable for occupancy in the EDG building when the EDGs are not in operation. During emergency conditions when the EDGs are operating, the engine cooling system fan provides the ventilation air flow through the EDG building to maintain its required temperature. The licensee states that the EPU does not affect the design capacity of the EDG. Therefore, the EPU does not impact the EDG building ventilation system to provide the required conditions for personnel and equipment.

The intake structure ventilation system provides ventilation air for reliable operation of the intake cooling water (ICW) system equipment, and to maintain the required temperatures during normal operation and under accident conditions. The licensee states that the EPU does not add heat loads to the intake structure enclosure and there are no changes to the intake structure ventilation system. Therefore EPU does not impact the intake structure ventilation system to provide acceptable temperature conditions for equipment operation during normal operation and emergency conditions.

The component cooling area ventilation system provides ventilation to assure a controlled thermal environment in the CCW system area. Exhaust fans and ductwork are provided for personnel comfort during normal operation. Without operation of exhaust fans, natural ventilation maintains the required design temperatures during normal operations and under accident conditions, and therefore the component cooling area ventilation system is non-safety-related. There are no changes proposed for the component cooling area ventilation system under EPU conditions. The licensee states that EPU will increase the heat load from the CCW and ICW piping and HXs, however the increase remains within the capability of the component cooling area ventilation system to maintain the design temperature during accident conditions. In an RAI the licensee was requested to justify taking credit for the use of a non safety-related system to maintain the required EPU design temperature in the component cooling area during accident conditions. In its response (Reference 26), the licensee proposes a revision to the related licensing report paragraph. In the revised paragraph, the licensee states that the heat gains from the CCW and ICW piping and HXs in the CLB analysis for accident conditions bound those at EPU such that natural ventilation will continue to maintain the component cooling area temperature below 120 °F. The licensee did not credited operation of the non safety-related closed cooling area ventilation for maintaining the temperature below 120 °F during an accident under EPU conditions. For the normal operation under EPU conditions, the licensee states that the analysis shows that the space temperature will increase by approximately 1°F, without taking credit for the operation of the ventilation fans. Therefore, the component cooling area ventilation system's capability to provide appropriate ventilation to ensure acceptable temperature conditions for equipment operation during normal and accident conditions is not impacted by EPU.

The licensee determined that there is no need to change ESF ventilation systems for the proposed EPU that could create a new potentially unmonitored radioactive release path. Thus, St. Lucie 2 will continue to meet its CLB with respect to GDC 60.

<u>Conclusion</u>

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

2.7.7 Other Ventilation Systems (Containment)

Regulatory Evaluation

The functions of the containment ventilation systems is to provide heat removal from the containment atmosphere and selected areas within containment, to remove radioactive materials from the containment atmosphere, and to provide containment pressure control under normal and accident conditions. The NRC staff review of the containment ventilation systems focused on the effects that the EPU will have on the functional performance of the systems. The acceptance criteria for the containment ventilation system are based on (1) GDC 4, insofar as it requires that safety-related SSCs be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC 38, insofar as it requires that the containment heat removal system(s) function to rapidly reduce the containment P-T following any LOCA and maintain them at acceptably low levels; (3) 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; (4) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

Technical Evaluation

The containment ventilation systems consists of eight systems which are: (1) containment cooling system, (2) CEDM cooling system, (3) reactor support cooling system, (4) reactor cavity cooling system, (5) containment vacuum relief system, (6) containment purge system, and (7) continuous containment/hydrogen purge system, and (8) hydrogen control system.

The containment cooling system removes heat from the containment during normal operation and following an accident by supplying cooled air to various regions inside the containment. The licensee states that under EPU condition, the increased heat load from the containment heat sources results in a slight increase of containment bulk air temperature, but the increase will not exceed the maximum normal operating bulk temperature limit of 120 °F. There are no changes to the containment cooling system under EPU conditions. The existing system will continue to perform its intended function under the EPU conditions and therefore is in compliance with GDC 38. The NRC staff agrees with the licensee's evaluation of the containment cooling system under EPU conditions.

The CEDM cooling system ventilates the CEDM magnetic jack coils and maintains them at a temperature below 350 °F. The licensee's evaluation of the CEDM cooling system concluded that the CEDM heat load does not change for EPU conditions. This licensee's EPU evaluation considered bounding values of the parameters that were used in the existing analysis and determined that the change under the EPU conditions is negligible. Therefore EPU does not affect the CEDM cooling system, and the cooling system will continue to perform its design function. The NRC staff agrees with the licensee's evaluation of the CEDM cooling system under the EPU conditions.

The reactor support cooling system cools to limit the temperature of the lubrication plates between the reactor and support leg in order to restrict thermal growth of the supporting steel work for the RV. The licensee estimated an approximate 1 percent increase in the heat load for the system and states that this increase is bounded by the design conditions. Therefore EPU does not affect the reactor support cooling system and the cooling system will continue to perform its design function under the EPU conditions. The NRC staff agrees with the licensee's evaluation of the reactor support cooling system under the EPU conditions.

The reactor cavity cooling system ventilates the annular space between the RV and the concrete primary shield wall to limit the concrete surface temperature in order to minimize the possibility of concrete dehydration. The licensee's evaluation of the heat load from the RV was shown to increase by approximately 1 percent. Therefore the reactor cavity cooling system heat load from its heat sources would increase by the same amount (i.e., approximately 1 percent). The licensee states that the increase in heat load does not affect the reactor cavity cooling system. Therefore, the reactor cavity cooling system will continue to perform its design function following the EPU. The NRC staff agrees with the licensee's evaluation of the reactor cavity cooling system under the EPU conditions.

The containment vacuum relief system provides protection of the containment vessel against excessive external pressure by preventing the DP between the containment and the shield building atmosphere from exceeding the design value of 0.70 psi. The licensee evaluated the containment vacuum relief system and confirmed that the EPU does not affect the operation of the system at its design basis event, which is the inadvertent operation of the CS system while all fan coolers are in operation and the containment is temperature is 90 °F at 20-percent relative humidity. The licensee states that the EPU does not affect the overall containment vacuum relief system. The NRC staff agrees with the licensee's evaluation of the containment vacuum relief system under the EPU conditions.

The containment purge system is designed to reduce the level of radioactive contamination in the containment atmosphere below the limits of 10 CFR Part 20 so as to permit personnel access to the containment during shutdown and refueling. The licensee states that the EPU may result in an increase in the inventory of airborne radionuclides in the containment atmosphere by approximately 12.2 percent. However, radiological offsite doses will continue to be within regulatory limits due to continued implementation of actions described in the plant offsite dose calculation manual to maintain doses ALARA. The EPU does not affect the present containment purge system. Therefore, the containment purge system will continue to perform its design function following EPU in compliance with GDC 60. The NRC staff agrees with the licensee's evaluation of the containment purge system under the EPU conditions.

The continuous containment purge/hydrogen purge system (a) provide a sufficiently low concentration of radionuclides in the containment atmosphere in order to allow required access time for plant operators during inspection and maintenance operations, (b) provide a means of relieving containment pressure buildup as a result of instrument air leakage and/or containment atmosphere temperature fluctuations, and, (c) provide the capability of ensuring that the containment source term contribution to the annual average offsite doses is maintained ALARA, and provide a hydrogen removal capability. The licensee states that the EPU does not affect the continuous containment purge/hydrogen purge system to perform its design functions. The NRC staff agrees with the licensee's evaluation of continuous containment purge/hydrogen purge system under the EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the containment ventilation systems. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the capability of these systems to perform their intended functions. The NRC staff also concludes that containment ventilation systems will continue to meet the requirements of GDC 4, 38, 41, and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the containment ventilation systems.

2.8 Reactor Systems

2.8.1 Fuel System Design

Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids, and springs, end plates, 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 margin 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 margin for stuck rods, to assure the capability to cool the core is maintained; and

(4) GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA. Specific review criteria are contained in SRP Section 4.2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

As described in the licensing report (Section 2.8.1.2 of Reference 2), the existing 16x16 CE HID (High Impact Design)-1L fuel assembly will remain unchanged for the upcoming EPU operation. NSSS T-H and neutronic conditions at EPU operation are listing in (Table 1.1-1 of Reference 2) for 0 percent SGTP and 10 percent SGTP. These NSSS parameters are based on 3030 MWt which equals the licensed power of 3020 MWt plus power measurement uncertainty. FPL has requested approval for a range of core inlet temperature from 535 °F to 551 °F. In CENPD-139-P-A (Section 1.1.4 of Reference 32), the licensee states that the analyses and evaluations were based on the parameter sets that were most limiting, so that the analyses would support operation over the entire range of conditions specified.

Changes in operational parameters which impact fuel system design and performance include increased reactor power (and associated increase in core average LHR and heat flux), increased RCS flow rate, increase in core inlet, core average, and core exit coolant temperature, and any changes in axial and radial power histories. This technical evaluation will focus on the impact of these EPU related changes on the performance of the 16x16 CE HID-1L fuel assembly design.

2.8.1.1 Fuel System Design features

The fuel system design for the EPU at St. Lucie 2 will remain the 16x16 CE HID -1L. The key features of the 16x16 CE HID-1L fuel assembly are as follows:

- ZIRLO fuel rod cladding,
- Zircaloy-4 guide thimbles,
- Gadolinia burnable absorber fuel rods,
- HID-L Zircaloy-4/OPTIN mid spacer grids,
- Bottom Inconel, GUARDIAN grid for debris protection,
- Low cobalt removable top nozzle,
- Low cobalt bottom nozzle,
- Inconel top spacer grid,
- 0.382 inch outside diameter fuel rods,
- 136.7 inch pellet stack length, and
- Licensed to a peak pin burnup of 60 GWd/MTU (Reference 33).

2.8.1.2 Mechanical Compatibility and Performance

Since the fuel mechanical design is not being changed for the EPU application, there are no transition core effects. The fuel mechanical design evaluations considered the effects of higher temperatures and uplift forces (1) on fuel rod stress, strain, fatigue, and collapse; (2) on fuel assembly stresses during seismic/LOCA events; and (3) on fuel assembly dimensional changes. The licensee has reported that, with respect to the fuel mechanical compatibility and performance, it is confirmed that the fuel design is structurally and mechanically acceptable for the EPU.

The fuel assemblies have been constructed capable of withstanding the loads resulting from potential mechanical excitations from seismic and/or LOCA events while ensuring that (1) fuel rod fragmentation does not occur, (2) a coolable core geometry is maintained, and (3) control rod insertability is maintained. In the licensing report (Section 2.8.1.2.3 of Reference 2), the licensee stated that the existing core plate motions and vertical impact loads on the nozzles used in the seismic/LOCA analyses are unaffected by the EPU project. Since the fuel design does not change, the effects of the EPU on the fuel mechanical design are limited to changes in the uprate operating parameters. These changes have been accounted for in the fuel rod stress analysis, which show that the acceptance criteria continue to be satisfied.

Based upon the information presented in the licensing report (Section 2.8.1.2 of Reference 2), the staff finds the 16x16 CE HID-1L fuel assembly mechanical design acceptable for EPU operating conditions.

2.8.1.3 Fuel Rod Performance

As indicated in the licensing report (Section 2.8.1.2.4.1 of Reference 2), fuel rod design evaluations for the 16x16 CE HID-1L gadolinia and UO_2 fuel designs for the analyzed reactor core thermal power level of 3030 MWt, were performed using NRC-approved models and design criteria methods to demonstrate that fuel rod design criteria are satisfied. The fuel rod design criteria associated with each of the performance indicators are verified by **[**

]. The NRC-approved FATES3B (References 32; 34; 35) model for in-reactor behavior is used to assess the fuel rod performance over its irradiation history. FATES3B iteratively calculates the interrelated effects of temperature, pressure, cladding elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power.

The Westinghouse FATES3B Fuel Evaluation Model was designed to calculate the steady-state fuel rod temperature distribution, gap conductance, fuel and clad dimensions, fuel rod internal pressure (RIP), and stored energy for nuclear fuel rods. The FATES3B fuel performance code incorporates detailed models of fuel and cladding that were developed to describe gap closure, and to account for the effects of power history and axial power variation.

FATES3B models the fuel pellet as a right circular cylinder, and accommodates volumetric changes due to fuel thermal expansion, densification, relocation, and fission-induced swelling. The code models the **[**

].

The calculation method in FATES3B accounts for the **[**

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<u>Thermal Conductivity Degradation</u>: FATES3B does not explicitly model thermal conductivity degradation (TCD) with burnup. The FATES3B code utilizes the Lyons correlation for predicting fuel thermal conductivity at zero burnup (Reference 32). The fuel pellet decreases in density due to burnup dependent swelling due to accumulation of both gaseous and solid fission products and due to fuel pellet cracking. This decrease in density results in a decrease in thermal conductivity. A porosity correction to thermal conductivity is included in FATES3B model based on the Maxwell-Euken relationship (Reference 32). Depending on the amount of in-reactor densification, a typical porosity induced reduction factor for thermal conductivity at 60 GWd/MTU is generally in the range of 2 to 4 percent.

The licensee performed an evaluation of Halden fuel data that simulate all high burnup fuel effects and compared the results with FATES3B fuel thermal performance model results. **[**

(Reference 36)**]**.

[

(Reference 37)**]**. The license condition states that, for St. Lucie Unit 2, FPL will maintain more restrictive operational/design radial power fall-off (RFO) curve limits. **[**

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In addition to reviewing the justification for the radial fall-off curve penalty to account for TCD effects, the staff performed independent calculations using FRAPCON-3.4 (References 38; 39) to confirm that the St. Lucie 2 fuel rod design satisfied design requirements at EPU conditions. These independent calculations are discussed in further detail below. **[**

], the staff finds this interim solution for addressing TCD acceptable at St. Lucie 2.

2.8.1.3.1 Input Parameters, Assumptions, Acceptance Criteria, Analyses and Evaluations

The design bases for the 16x16 CE HID-1L fuel assembly with ZIRLO cladding is discussed in CENPD-404-P-A (Reference 33). Fuel rod design evaluations for the fuel were performed using NRC-approved models and NRC-approved fuel rod design criteria. The changes in the operating conditions, and specifically, the operating temperatures associated with the EPU condition were considered in the fuel rod design analysis as reported in this section.

The licensing report (Section 2.8.1.2.4 of Reference 2) describes the fuel rod design analyses. After reviewing this submittal, the staff requested further details of the design calculations. In response to RAI SRXB-25 (Reference 40), FPL provided further information on the fuel rod design analyses.

Clad Oxidation and Hydriding: The design criteria for clad corrosion for ZIRLO cladding requires that the maximum predicted best estimate oxide thickness remains below 100 microns for all locations of the fuel. Also the modified duty index (mFDI) for ZIRLO clad fuel will be restricted to **[ ]**, while a fraction of the fuel pins in a limited number of assemblies (eight) will have mFDI restricted to **[ ]** (References 40; 33). These design criteria are consistent with license conditions in the St. Lucie 2 plant TSs.

The methodology and model described in Reference 3 was used to confirm that the maximum mFDI for any fuel rod at any time in life is less than the NRC approved criterion. The maximum mFDI predicted in the EPU reference analyses is less than the criterion. The licensee shall evaluate the maximum mFDI in cycle specific EPU analyses and confirm to be less than the criterion (Reference 40).

Based upon continued adherence to current licensed basis and cycle-specific confirmation, the staff finds the fuel rod cladding oxidation and hydriding evaluation acceptable for EPU conditions.

Cladding Creep Collapse: The criterion for cladding creep collapse for continuous reactor operation during normal operation, AOO, or emergency condition event is that the time required for the radial buckling of the cladding in any UO_2 or gadolinia absorber fuel rod must exceed the reactor operating time necessary for the appropriate batch to accumulate its design average discharge burnup. This criterion will be considered satisfied if it can be demonstrated that (1) axial gaps longer than **[ ]** inches will not occur between the fuel pellets and (2) the **[ ]** is sufficient to prevent cladding collapse under all design conditions.

A detailed cladding creep analysis was performed by considering EPU conditions to demonstrate that cladding collapse does not occur in any fuel assembly at any time during the fuel operating life, which is considered out to a burnup of **[ ]** using the methodology of CENPD-404-P-A (Reference 33). The evaluation considered differential cladding pressure, cladding temperature, cladding flux, and cladding thinning due to oxidation, all as a function of time. The methodology involves the use of CEPANFL code which calculates cladding ovality as a function of time until the rate of ovality increase becomes excessive, at which time the cladding is considered to collapse. The code uses three categories of information to perform this calculation, 1) cladding properties, 2) operating conditions, and

3) pellet column gap length. The EPU analyses have demonstrated that for the expected fuel operating life-time, no cladding creep collapse was predicted.

Based on the use of approved methods and compliance with acceptance criteria, the staff finds the cladding creep collapse evaluation acceptable for EPU conditions.

Clad Stress: During normal operation and AOO events, the primary tensile and compressive stresses in the cladding and end-cap welds must not exceed **[ ]**. The stresses are also examined for emergency and accident conditions. The RIPs used to perform the stress analyses of the fuel rod designs account for **[ ]**. The rod external pressures are biased in the conservative direction (maximum compressive and minimum tensile stresses). The maximum compressive and tensile stresses were calculated for fuel handling and storage, BOL rod withdrawal, power operation and reactor trip, heatup and cooldown, OBE, design-basis earthquake, LOCA, and combined design-basis earthquake+LOCA.

The maximum tensile stresses for the different events analyzed demonstrated that for the EPU, there was at least **[ ]** to the allowable tensile stress limits. For the maximum compressive stresses, it was demonstrated that for the EPU there was at least **[ ]** to the allowable compressive stress limits.

Based on the use of approved methods and compliance with acceptance criteria, the staff finds the cladding stress evaluation acceptable for EPU conditions.

Clad Strain: The design limit for cladding strain is that the total plastic tensile creep strain due to uniform cladding creep and uniform cylindrical fuel pellet expansion, due to swelling and thermal expansion is less than 1 percent from the unirradiated condition, and that the total tensile strain due to uniform cylindrical pellet expansion during a transient is less than 1 percent from the pre-transient value. The methodology is discussed in CENPD-404-P-A (Reference 33) and the details are given in (Reference 40).

The first part of the strain limit involves the total plastic strain as a result of cladding creep and cladding yielding during long term normal operation and short transient conditions. Conservatism in the calculations is achieved by considering peak local burnups that are based on a rod average burnup of 65 GWd/MTU.

Permanent strain resulting from normal operation is determined by applying differential pressure to the cladding, resulting in a stress distribution that causes the cladding to creep due to thermal and irradiation effects. At the end of each time step of calculation, by applying the ZIRLO creep correlation to the stress distribution, the creep strain is calculated and the cladding diameter is adjusted to include the creep strain. The methodology to evaluate strain accounts for power dependent and time dependent parameters, including differential pressure across the cladding, cladding temperature, pellet diameter, and clad diameter. The new pellet diameter is compared to the new cladding diameter, and if there is interference between the two, the interference strain is compared to the yield strain to determine if yielding has occurred. Any strain that is higher than the yield strain is considered to be permanent strain, and the cladding diameter is adjusted accordingly. This process is repeated at the end of each time step, and the resulting cladding diameter is compared to the end of life (EOL) diameter to determine the amount of permanent strain that has occurred. As time goes by, the cladding strain reverses direction as the RIP increases and the pellet expands. For the EPU case, the reversal at the EOL is not sufficient to surpass the early compressive strain, and the final permanent strain due to normal operation remains slightly compressive. To satisfy the criterion, the normal operating plastic strain combined with the transient plastic strain must be less than 1 percent tensile.

Compliance with the transient induced strain limit is demonstrated by **[**

]. For EPU, it was demonstrated that the total plastic tensile creep strain due to uniform cladding creep and uniform cylindrical fuel pellet expansion due to swelling and thermal expansion is less than 1 percent from the unirradiated condition, and that the total tensile strain due to uniform cylindrical pellet expansion during a transient is less than 1 percent from the pre-transient value (Reference 40).

In addition to reviewing the material provided by the licensee (References 2; 40), the staff performed independent cladding strain calculations (Reference 38) using the NRC audit code FRAPCON-3.4 (Reference 39). FRAPCON-3.4 calculations were run using the St. Lucie 2 UO_2 fuel rod design and the limiting pre/post-LHGR curve generated with FATES3B. AOO over-power ramps were simulated at exposure points corresponding to 24 GWd/MTU and 44 GWd/MTU. The staff's independent calculations provide confirmation that the St. Lucie 2 fuel rod design satisfies the 1.0 percent transient cladding strain design limit during the limiting AOO overpower scenario at EPU conditions.

Based upon the use of approved methods, compliance with acceptance criteria, and independent calculations, the staff finds the cladding strain evaluation acceptable for EPU conditions

<u>Clad Fatigue</u>: For the number and type of transients that occur during normal operation, the EOL cumulative fatigue damage factor in the cladding and in the end-cap welds must be **[**
]. The methodology for the fuel rod cladding strain analysis is discussed in CENPD-404-P-A (Reference 33). Fuel rod fatigue evaluation to support the EPU considered the differential cladding and cladding temperatures associated with the EPU, cladding creep, and pellet swelling and demonstrated that the above design requirement was satisfied.

Fatigue damage to the fuel rod cladding is caused by reactor trips, startups and shutdowns, and power cycling. The methodology used to assess the fatigue damage from power cycling is the same as described above for strain evaluation during normal operation, except that some of the parameters are biased in the opposite direction to provide conservative results for fatigue analysis. The power is conservatively assumed to vary between 10 percent and 100 percent on a daily basis. For LOCA, a 100 percent power is assumed. For each day, the maximum strain range resulting from the changes in power is determined. The allowable number of cycles for that strain range is determined based on the fatigue design curve, and the reciprocal of that number is the fatigue damage factor for that day. This process is repeated for each day of operation, where the number of days is the number required to achieve the peak local burnup, which is based on a rod average burnup of 65 GWd/MTU. The fatigue damage factors from all the days of operation are totaled to give the cumulative damage factor of 0.68 due to power cycling.

Similar methodology is repeated for determining the damage associated with the reactor trips, and startups/shutdowns. The resulting cumulative damage factors are **[** **]** startups and shutdowns between **[** **]**. The total cumulative fatigue damage factor from power cycling, reactor trips and startups/shutdowns is **[** **]**, which is below the limit of **[** **]**.

Based on the use of approved methods and compliance with acceptance criteria, the staff finds the cladding fatigue evaluation acceptable for EPU conditions.

<u>Rod Internal Pressure</u>: FATES3B was used to calculate the RIP and corresponding critical pressure limit according to the NRC-approved methodology (References 35; 41). The critical pressure limit is the internal hot gas pressure at which the outward tensile creep rate of the cladding exceeds the fuel pellet radial growth rate due to fuel swelling, thus creating an increasing fuel-clad gap.

The hot internal pressure of **[** **]** was calculated at all times in life, under EPU conditions, taking into account AOOs, using the FATES3B code. As part of the reload safety evaluation process, the maximum allowable RIP calculated at all times in life for EPU conditions is verified every cycle to remain below the critical pressure limit during normal operation and AOOs.

The NRC staff used the FRAPCON statistical package (Reference 39) to perform benchmark design calculations for the RIP to confirm the licensee's RIP calculations. The statistical package randomly samples among specified distributions of manufacturing tolerances, modeling uncertainties, and rod power uncertainties to create multiple input decks, executes each of these unique cases, and compiles the results. FRAPCON-3.4 RIP calculations were performed for (1) the limiting UO_2 and Gadolinia fuel rod power histories from the St. Lucie 2 EPU fuel management study and (2) segmented power histories based upon the bounding radial power fall-off curve. The UO_2 and 4 percent Gd RFO curves (rod average power) were segmented into 7 power profiles. In response to staff concerns, the licensee proposed a TCD rod power penalty based upon FATES-3B comparisons to Halden fuel temperature measurements. A rod power penalty equivalent to a 200 °F decrease in predicted fuel centerline temperature above 50 GWd/MTU was proposed.

The NRC staff's independent calculations provide confirmation that the St. Lucie 2 fuel rod design has adequate rod internal void volume to accommodate fission gas release at EPU conditions and that the proposed RFO curve (with TCD penalty) ensures that RIP remains below the clad lift-off design criterion.

Based upon the use of approved methods with application of the proposed RFO curve penalty, compliance with acceptance criteria, and independent calculations, the staff finds the EOL RIP evaluation acceptable for EPU conditions.

<u>Fuel Rod Growth, Assembly Growth and Shoulder GAP</u>: The axial length between the end fittings must be sufficient to accommodate the differential thermal expansion and irradiation-induced differential growth between the fuel rods and the guide tubes, such that it can be shown with a 95 percent confidence level that no interference exists.

Since guide tube and fuel rod design and materials are unchanged, existing growth models and their supporting database of pool-side measurements remain applicable. EPU does not invalidate these models, since growth is correlated to fluence.

The shoulder gap is affected by the fuel assembly growth and the fuel rod growth. Prior analyses with non-EPU conditions have demonstrated adequate shoulder gap margin. The only change that affects fuel assembly growth for EPU conditions is a slight increase in uplift forces on the spacer grids due to the slight increase in coolant temperature associated with EPU. This increase in uplift forces results in a slight increase in fuel assembly growth which increases shoulder gap. It was concluded by the licensee that the shoulder gap will be slightly greater for EPU conditions than for non-EPU conditions.

Based upon the continued applicability of assembly and fuel rod growth predictions, the staff finds the shoulder gap evaluation acceptable at EPU conditions.

Fuel Coolability: The assembly must retain its rod-bundle geometry with adequate coolant channels to permit removal of residual heat. Reduction of coolability can result from cladding embrittlement, violent expulsion of fuel, generalized cladding melting, gross structural deformation, and extreme coplanar fuel rod ballooning. The loads that originate during faulted conditions caused by motions of the upper and lower core plates, and lateral deflections and impacts transmitted through adjacent assemblies, the core plates, and the core baffle should not result in fuel assembly deformations which would prevent coolability or the ability to insert control rods.

Mechanical analyses were performed to demonstrate that fuel coolability and the ability to insert control rods can be maintained at the EPU conditions.

Fuel Centerline Melt (FCM): The NRC-approved FATES3B code and the approved methodology for gadolinia fuel rods (Reference 42) are used to calculate the maximum fuel rod temperatures during normal operation and AOOs. The maximum calculated temperatures are shown to be less than the fuel melting temperatures at any time in life. The maximum fuel rod temperatures calculated for gadolinia and UO_2 fuel rods at all times in life for EPU conditions in the reference analyses remain below the fuel melting temperatures during normal operation and AOOs.

The staff performed independent power-to-melt limit calculations using the NRC audit code FRAPCON-3.4 (Reference 38). The calculations show that overly conservative fuel melting temperatures compensate for TCD effects at higher exposure and therefore, the FATES-3B power-to-melt limits are conservative.

Cycle specific analyses will be performed to verify that local rod power remains below these power-to-melt limits at all times in life for EPU conditions. This ensures that maximum fuel rod temperatures for gadolinia and UO_2 fuel rods remain below fuel melting temperatures during normal operation and AOOs.

Based upon the use of approved methods, cycle-specific compliance with acceptance criteria, and independent calculations, the staff finds the fuel centerline melt evaluation acceptable for EPU conditions.

Departure from Nucleate Boiling (DNB) Propagation: The licensing report (Section 2.8.1.2.4.3 of Reference 2) describes the fuel rod DNB propagation evaluation. Calculation of DNB propagation depends on rod internal gas pressure, high-temperature creep, and high-temperature rupture stress (burst stress). FPL's evaluation demonstrated that no DNB propagation will occur with the maximum RIPs predicted for St. Lucie Unit 2. The licensee's application goes on to state:

> If conditions change, the changes will be evaluated as part of the reload safety evaluation process to verify the lack of DNB propagation or to demonstrate that with DNB propagation the radiological dose consequences of DNB failures will remain within the specified limits.

The staff does not accept the alternate whereby DNB propagation is allowed. Future reload analyses must demonstrate that DNB propagation does not occur.

2.8.1.3.2 Fuel Rod Performance - Results

The licensee performed fuel performance evaluations for EPU transition and equilibrium cycles to demonstrate that the fuel design criteria can be satisfied for all rod types in the St. Lucie 2 core under the planned EPU operating conditions. The increase in power will have an impact on the fuel rod design margin. The NRC staff has determined that all design requirements are met under EPU conditions. These criteria will be verified for each cycle.

Based on the licensee's evaluations and NRC staff's review of these evaluations, as well as independent FRAPCON-3.4 calculations, the staff finds that the fuel rod design criteria has been satisfied for St. Lucie 2 EPU conditions.

Conclusion

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

2.8.2 Nuclear Design

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 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 reactor vessel internals so as to significantly impair the capability to cool the core.

Specific review criteria are contained in SRP Section 4.3 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The purpose of EPU core design analysis is to determine a range of neutronic parameter values for the key safety parameters to be used in the EPU analysis. The core analysis also determines the basis for any changes to the limits in the COLR. The primary physics codes used in the analyses are (References 43; 44).

2.8.2.1 Input Parameters, Assumptions, and Acceptance Criteria

The key features of the CE 16x16 HID-1L design are:

- 0.382 inch outside diameter fuel rods,
- Solid axial blanket pellets,
- 136.7 inch pellet stack length,
- ZIRLO fuel rod clad, and
- Radial enrichment zoning.

Core safety parameters such as power distributions, peaking factors, rod worths, and reactivity parameters are core loading pattern dependent and they vary cycle-to-cycle. The loading pattern dependent safety parameters for EPU cycle will be similar to the cycle-to-cycle variations for past cycles.

The radial peaking factor (F_R^T) has been reduced to offset the impact of EPU on core thermal hydraulics and fuel rod performance. There are no changes in the nuclear design philosophy or methods due to the transition to EPU. WCAP-9272-P-A (Reference 45) describes the reload design methodology that includes the evaluation of the reload core key parameters (Table 2.8.2-2 of Reference 2). These parameters will be evaluated for each reload cycle. If any of these parameters fall outside the bounds assumed in the reference safety analysis, the affected transients shall be re-evaluated or re-analyzed using the accepted methodology and the results should be documented in the reload evaluation for that cycle.

The licensing report (Table 2.8.2-2 of Reference 2) provides listing of a range of current key safety parameters and their corresponding EPU equilibrium cycle analysis values. The list consist of reactor core power, vessel average coolant inlet temperature, nominal coolant system pressure, moderator temperature coefficients, Doppler temperature coefficients, shutdown margin, linear heat generation rate, axial shape index, and hot zero power (HZP) and hot full power (HFP) control rod worths, maximum ejected rod worth, maximum ejected rod $F_Q(Z)$, and least negative isothermal temperature coefficient.

2.8.2.2 Description of Analyses and Evaluations

This section evaluates the effects of transitioning to EPU conditions on the nuclear design bases and methodologies. The licensee employed analytical models and methods (References 43; 44; 45) for the EPU nuclear design analysis at St. Lucie 2.

The licensee has developed core designs for several typical EPU reload cycles to model the transition to equilibrium EPU conditions based on a nominal projected energy requirement of 515 effective full-power days as listed in the licensing report (Table 2.8.2-1 of Reference 2). These core designs were developed with the intent to determine limiting parameters for safety analysis to allow enough margin between expected EPU parameter values and the corresponding safety analysis limits (SALs) for flexibility in designing actual EPU reload cores. Cycle-specific calculations confirm that the actual values are within the SALs. The values for the EPU cycles were compared to values for recent reload cycles to evaluate the continued adequacy of margins between typical safety parameter values and the corresponding limits.

For the EPU at St. Lucie 2 the CE 16x16 HID-1L fuel design shall remain at a licensed peak pin burnup of 60 GWd/MTU (Reference 46). The licensing report (Table 2.8.2-2 of Reference 2) lists results from the calculation for shutdown margin and control rod worths that considered several CEA patterns.

2.8.2.3 Results

Margin to key safety parameter limits (Table 2.8.2-2 of Reference 2) is not significantly reduced by the CE 16x16 fuel design for St. Lucie 2 operation at EPU conditions.

The variations in key safety parameters are typical of the normal cycle-to-cycle variations due to the change in fuel loading pattern. Core power distributions and peaking factors typically vary cycle-to-cycle based on actual energy requirements. Compliance with TS values for peaking factors are assured using the NRC-approved methods.

In view of the licensee's use of the CE 16x16 fuel design that accommodates the EPU and extended burnup operation, the fact that the reported EPU nuclear design data by the licensee indicates little changes from current nuclear design parameters, and the fact that each cycle's core will be analyzed using NRC-approved methods, the NRC staff finds reasonable assurance that the St. Lucie 2 uprated core nuclear design will remain acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the proposed EPU 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 EPU 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, 11, 12, 13, 20, 25, 26, 27, and 28. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the nuclear design.

2.8.3 Thermal and Hydraulic Design

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 T-H instability.

The review also covered hydraulic loads on the core and RCS components during normal operation and DBA conditions and core T-H stability under normal operation and 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 provided in Matrix 8 of RS-001.

Technical Evaluation

The T-H analysis supporting the EPU incorporates the increased core power and addresses the DNB performance, that includes the effects of rod bow and bypass flow. This means that the fuel assembly flow area and the hydraulic resistance are unchanged between the pre-EPU and post-EPU fuel design. The current licensing basis for T-H analysis includes the prevention of DNB on the limiting fuel rod with a 95 percent probability at a 95 percent confidence level and criteria to ensure fuel cladding integrity. Therefore there are no T-H compatibility or stability issues associated with a transition core.

2.8.3.1 Input Parameters, Assumptions, and Acceptance Criteria

The licensing report (Table 2.8.3-1 of Reference 2) lists the T-H parameters for the current design at 2700 MWt as well as for the EPU design at 3030 MWt with the limiting direction for DNB given in the licensing report (Table 2.8.3-1 of Reference 2). The T-H DNBR analysis of the 16x16 standard fuel in St. Lucie 2 is based on the revised thermal design procedure (RTDP) (Reference 47) and the ABB-NV DNB correlation (Reference 48) using the VIPRE-W subchannel analysis code (Reference 49). The analysis demonstrates that 95/95 design basis is met for the core while operating at the uprated power. The licensee has complied with the conditions specified in the NRC SER for the VIPRE-W code that is used for DNBR calculations at St. Lucie 2.

The overall DNB uncertainty factors are obtained by using the RTDP methodology in which uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically. The

RTDP design limit DNBR values are determined such that there is a 95 percent probability at a 95 percent confidence (95/95) that DNB will not occur on the most limiting fuel rod during normal operation and AOOs. The overall DNB uncertainty factor includes the uncertainties in nuclear enthalpy rise hot channel factor ($F^N_{\Delta H}$ or F_r),[2] enthalpy rise engineering factor ($F^E_{\Delta H}$ or F_r),[3] uncertainties in the VIPRE-01 and transient codes, vessel coolant flow, effective core flow fraction, core thermal power, coolant temperature, system pressure, rod pitch, and rod outer diameter. Table 2.8.3-3 provides peaking factor uncertainties, together with a listing and description of the peaking factor uncertainties.

Sufficient DNBR margin is conservatively maintained in the safety analysis DNBR limits to offset the rod bow, potential future DNBR penalties, and to provide flexibility in design and operation of the plant. Table 2.8.3-5 provides the DNBR margin and penalties applicable at EPU conditions.

The NRC accepted value for ABB-NV 95/95 DNB correlation limit for 16x16 standard fuel assemblies, as documented in WCAP-11397-P-A (Reference 47), is 1.13. For the EPU analysis, the RTDP design limit DNBR values are 1.30, 1.29, and 1.32 for small thimble, large thimble, and matrix (typical) cells, respectively. After accounting for the plant-specific margin, the SAL DNBR is set to **[ ]** for the matrix and thimble cells, respectively. For events where standard thermal design procedure (STDP) is used, the ABB-NV correlation DNBR limit is 1.13.

The reactor core is designed to meet the following thermal and hydraulic criteria:

- There is at least a 95 percent probability at a 95 percent confidence level that DNB will not occur on the limiting fuel rods during Modes 1 and 2, operational transients, or any condition of moderate frequency;

- No fuel melting during any anticipated normal operating condition, operational transients, or any conditions of moderate frequency; and

- Mode of operation under normal operation and AOOs will not lead to thermo-hydrodynamic instabilities.

Analytical assurance that DNB will not occur is provided by showing the calculated DNBR to be higher than the 95/95 limit DNBR for conditions of normal operation, operational transients, and transient conditions of moderate frequency. The design limit DNBR is calculated by using the RTDP methodology, which, for all operating conditions, assures compliance with the DNBR criteria above.

Based upon the use of an approved DNB critical heat flux (CHF) correlation and models and cycle-specific compliance to acceptance criteria, the staff finds the T-H design acceptable at EPU conditions.

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[2] This is the ratio of the relative power of the hot rod, which is one of the rods in the hot channel, to the average rod power.
[3] The nominal enthalpy rise in an isolated hot channel is calculated by dividing the nominal power in to this channel by the core average inlet flow per channel.

2.8.3.2 Results

The results of the analyses demonstrate that the event-specific acceptance criteria are met for EPU operation. The compliance with the acceptance criteria is verified on a cycle-by-cycle basis as part of the cycle specific reload evaluation. The results for non-LOCA events that were analyzed for EPU are listed in the licensing report (Table 2.8.5.0-10 of Section 2.8.5.0 of Reference 2).

The CE 16x16 HID-1L design allows power operation at a radial peaking limit of 1.65. The T-H design criteria are satisfied for the EPU. The anticipated reduction in margin has been offset by (1) reduction in the radial peaking limit and (2) an increase in the TS minimum flow rate.

Conclusion

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

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

Regulatory Evaluation

The NRC staff's review covered the functional performance of the CRDS to confirm that the system can effect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CRDS cooling system to ensure that it will continue to meet its design requirements. The 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 reactor vessel 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.

Specific review criteria are contained in SRP Section 4.4 and other guidance provided in Matrix 8 of RS-001

Technical Evaluation

The St. Lucie 2 CRDS is referred to as CEDM. Each CEDM is capable of withdrawing, inserting, holding, or tripping the CEA from any point within its travel in response to operating signals. Each CEDM is connected to the CEA by an extension shaft. The extension shaft assemblies connect the CEDMs to the CEAs. The assemblies are of two types: the single, which is coupled to only one CEA and the dual, which is coupled to two CEAs.

The impact of EPU on the CEDM results from the temperature effects associated with increase in St. Lucie 2 thermal power level from 2714 MWt to 3034 MWt. This increase in rated thermal power (RTP) results in an increase in reactor vessel best estimate average temperature from 571.7 °F to 577.3 °F. The increase in RCS average temperature is expected to increase the best estimate reactor vessel head and CEDM temperature from 595 °F to 603.6 °F. The vessel head and the CEDM temperature are conservatively set to the hot leg temperature for the structural analysis of the components.

As a result of EPU, there are no physical changes required to the CEDM, operating coil stacks, power supplies, or the solid state electronic control cabinets.

2.8.4.2 Input Parameters, Assumptions, and Acceptance Criteria

There is no fuel design change with respect to fuel column length and there is no change in the upper end fitting. Also the fuel assembly interface with the CEA remains unchanged. The acceptance criteria is such that the CEDM design must demonstrate that the CEDM can effectively accomplish a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents under EPU conditions.

2.8.4.2.1 Analyses and Evaluations

Analyses and evaluations of the impact of EPU on the structural integrity of the CEDM during normal, transient, and accident conditions were performed using EPU conditions. The analyses were performed to determine the effects to the CEDM due to the increased power and associated increased thermal stresses, and the increased hydraulic, cyclic, and seismic forces associated with normal, transient, and accident conditions at EPU conditions. The analyses also included the evaluation of the effect of increased heat load to the CEDM cooling system resulting from the higher head temperatures.

The evaluation of the effects to the CEDM associated with EPU demonstrates that the CEDM can effect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents.

2.8.4.2.2 Results

The licensee has reviewed the functional design of the CEDM and the CEDM cooling system for the effects of EPU and has demonstrated that at EPU conditions the CEDM will continue to satisfy the design basis for reactivity control and ensure SAFDLs are not exceeded for any single malfunction of the reactivity control systems.

Conclusion

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

2.8.4.3 Overpressure Protection during Power Operation

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 QT, the charging system and the high-pressure safety injection (HPSI) system, and the SDC system (referred to as the RHR system in RS-001), which may be operating when the primary system is water solid.

The NRC's acceptance criteria are based on:

(1) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and

(2) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized.

Specific review criteria are contained in SRP Section 5.2.2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Section 5.1 of the FSAR states that overpressure protection for the RCPB is provided by the spring-loaded ASME code PSVs connected to the top of the pressurizer. Two PORVs are provided to minimize the opening of the PSVs. Overpressure protection for the secondary side of the SGs is provided by 16 spring-loaded ASME code safety valves located in the MSSS upstream of the MSIVs.

The licensee referred to the analyses of the limiting AOO and postulated accident in licensing report Section 2.8.5.2.1, "Loss of External Load, Turbine Trip and Loss of Condenser Vacuum," and licensing report Section 2.8.5.2.4, "Feedweater System Pipe Breaks Inside and Outside Containment," respectively to show that St. Lucie 2 is adequately protected against overpressure during power operation at the proposed EPU level. The limiting AOO with respect to primary and secondary system overpressurization was identified as the LOCV event and the limiting postulated accident was identified as the FWLB event. The analyses were performed by assuming that there was no direct reactor trip from the turbine trip. The direct reactor trip from the turbine trip was not assumed for any of the FSAR Section 15 accident analyses, since this trip signal originates in the turbine, a non-seismically qualified area.

The LOCV analysis documented in licensing report Section 2.8.5.2.1 showed that (1) with the PSVs setpoint at the proposed +/- 3 percent tolerance, the maximum primary system pressure was 2669.1 psia and (2) with the MSSVs setpoint at a +/- 3 percent tolerance on Banks 1, a +2/-3 percent tolerance on Banks 2, and a 3 percent accumulation on both banks, the maximum secondary system pressure was 1093.7 psia. Both maximum pressures in the primary and secondary system were within their respective safety limit of 2750 psia (110 percent of the design pressures of 2500 psia) and 1100 psia (110 percent of the design pressure of 1000 psia). Both LOCV and FWLB analyses were found acceptable with the bases discussed in Section 2.8.5.2.1 and 2.8.5.2.4 of this SE, respectively.

The analysis of the LOCV event in LR Section 2.8.5.2.1 relied on a reactor trip on the HPP trip signal. The HPP trip signal is the first safety grade signal from the RPS actuated during the LOCV event. For the design of the capacity for safety valves, SRP 5.2.2 specifies that the analysis of AOOs including LOCV should use the assumption that the creditable reactor trip is based on the second safety grade signal from the RPS. In addressing the SRP 5.2.2 guidance, the licensee reanalyzed the LOCV, the limiting AOO with respect to the overpressure events, and presented the results on pages 21 through 29 of Attachment 1 to its response to audit questions (Reference 50). The reanalysis was performed with the current licensed LOCV methodology. In the analysis, the reactor trip was delayed from the first safety grade reactor trip signal on HPP until actuation of the second safety grade reactor trip signal on SG low level. The reactor trip setpoint credited for the SG low level was 30 percent NR, which was reduced from the nominal value to account for the SG level uncertainty and was lower than the available value of 34.1 percent NR specified in the proposed TS Table 2.2-1, Functional Unit 8 of

Attachment 3 to the licensing report (Reference 2) for the SG low level trip. The use of a lower setpoint was conservative because it would delay the reactor trip and increase the energy stored in the RCS, which would result in a higher peak pressurizer pressure. The results listed in Table LOCV-4 of the licensee's response to audit questions (Reference 50) showed that the peak pressurizer pressure was approximately 2712 psia, which remained below the acceptable criterion of 2750 psia. Based on the assumption and results of the LOCV reanalysis, the NRC staff concluded that the LOCV reanalysis met the SRP 5.2.2 satisfactorily and was acceptable for the St. Lucie 2 EPU application.

The FWLB analysis documented in licensing report Section 2.8.5.2.4 showed that (1) with the PSVs setpoint at +/-3 percent tolerance the peak pressure in the primary system was 2704 psia, and (2) with the MSSVs setppoint at a +/- 3 percent tolerance on Banks 1, a +2/-3 percent tolerance on Banks 2, and a 3 percent accumulation on both banks, the peak pressure in the secondary system was 1094.27 psia. Both peak pressures in the primary and secondary system were within their respective safety limit of 3000 psia (120 percent of the design pressures of 2500 psia) and 1100 psia (110 percent of the design pressure of 1000 psia). The analysis of the FWLB event relied on the first safety grade reactor trip signal on HPP from the RPS. The SRP 5.2.2 guidance indicates that the second safety grade reactor trip should be used for sizing the safety valves; however, this guidance is only applicable to AOOs. Specifically, Acceptance Criteria Section 3 Item B of the SRP 5.2.2 states that "The designs of the safety valves should have sufficient capacity to limit the pressure to less than 110 percent of the RCPB design pressure during the most severe AOO with reactor scram…" Since the FWLB event is an accident, the specified SRP 5.2.2 guidance is not applicable to FWLB and the analysis of the FWLB event remains valid.

Based on the acceptable results of the analyses for the limiting AOO and accident with respect to primary and secondary system overpressurization, the NRC staff determined that the overpressure protection features would continue to provide adequate protection to meet GDC 15 and GDC 31 at EPU conditions. Therefore, the NRC staff concluded that the proposed EPU was acceptable with respect to overpressure protection during power operation.

Conclusion

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

2.8.4.4 Overpressure Protection during Low Temperature Operation

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 QT, the makeup and letdown system, and the RHR system which may be operating when the primary system is water solid. The NRC's acceptance criteria are based on (1) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (2) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized.

Specific review criteria are contained in SRP Section 5.2.2. The NRC staff's review also considered the effects of the increase in vessel fluence, due to the EPU, on the P-T limit curves and PTS pursuant to 10 CFR 50.61.

Technical Evaluation

Low-temperature overpressure protection (LTOP) system is designed to ensure that the 10 CFR Part 50, Appendix G, pressure vessel brittle fracture limits will not be exceeded in Modes 4, 5, or 6 under over-pressurization conditions. The LTOP for St. Lucie 2 is provided by PORVs connected to the pressurizer steam space and when the SDC system is in operation also by the SDC system relief valves. The LTOP setpoints of the PORVs and SDC system relief valves are 490 psia and 350 psia, respectively. Technical Specification Tables 3.4-3 and 3,4-4 specifies that the PORVs are used for LTOP during heat-up when any RCS temperature cold-leg temperature is in the range of 80-246 °F and during cool-down when any RCS cold-leg temperature is 224 °F and below to 132 °F. For temperatures below 132 °F during cooldown, the St. Lucie 2 relies on the SDC system relief valves for LTOP.

For LTOP considerations, the pressure setpoints and flow capacities of the PORV and SDC system relief valves are based on the analysis of two LTOP events previously identified in Section 5.2.6 of the St. Lucie 2 FSAR as the most limiting events. The events are (1) the mass addition event caused by charging and HPSI flows following an inadvertent safety injection actuation, and (2) the energy addition event caused by the restart of a RCP when a positive SG to reactor vessel ΔT exists.

In support of its EPU application, the licensee performed a LTOP analysis at EPU conditions and discussed the analysis in licensing report Section 2.8.4.3 and the licensee's response to RAI SRXB-46 in the licensee's RAI responses (References 11; 51). The NRC has reviewed the LTOP analysis and the associated RAI response, and provides the following evaluation.

The licensee performed the LTOP analysis using the methods (Reference 51) consistent with the current LTOP analysis methodology. Two cases were analyzed at EPU conditions. The cases were the mass addition and energy addition events, which were the limiting events for determination of the setpoints of the LTOP system identified in the FSAR. For the mass addition event, the analysis was performed for two worst cases:

(1) Two HPSI pumps and three charging pumps at temperatures greater than 200 °F; and

(2) A single HPSI pump and three charging pumps at temperature less than or equal to 200 °F. (This case was to reflect the TS LCO 3.5.3 conditions where only one HPSI pump would be operable when the RCS temperature is less than or equal to 200 °F.)

For the energy addition event, a ΔT of 40 °F was assumed between SG and RCS of an idle loop with inadvertent RCP activation. The assumed ΔT of 40 °F was conservative, since it was greater than the limit of the ΔT of 30 °F controlled by the licensee's administrative procedures, and would add more energy into the solid RCS. The assumed ΔT of 40 °F was also the temperature difference limit specified in the TS 3.4.1.3 for Mode 4 and TS 3.4.1.4.1 for Mode 5 with reactor coolant filled. The assumed startup of one RCP was acceptable since the simultaneous startup of more than one RCP was procedurally precluded by the licensee.

Although pressure relief for either event provided through the two PORVs or SDC system relief valves, the LTOP analysis assumed that only one PORV or SDC system relief valve was operable. For EPU conditions, only the values of the decay heat assumed in the LTOP analysis were directly affected by the power uprate. In maximizing the peak RCS pressure, the RCS was assumed in a water solid condition at initiation of the events. The maximum pressurizer heater input was used as an additional energy source.

A sensitivity study was performed in determining the effects of the pressure and temperature on the peak RCS pressure for the maximum operating range. In addition, the acceptance criteria of the LTOP analysis, the P-T limits and associated fluence limit would change because of reactor vessel exposure to different levels of neutron fluence.

The peak pressurizer pressures (Table 6 of Reference 51) calculated in the LTOP analysis are summarized below.

Condition			Peak Pressure (psia)
1.	Cooldown,	RCS Temperature < 132 °F	368.0
2.	Cooldown,	132 °F ≤ RCS Temperature < 200 °F	546.5
3.	Cooldown,	200 °F ≤ RCS Temperature ≤ 224 °F	677.0
4.	Heatup,	RCS Temperature < 200 °F	546.5
5.	Heatup	200 °F ≤ RCS Temperature ≤ 246 °F	677.0

The above peak pressure are within the P-T limits specified in TS 3/4.4.9. Since the methods used for the LTOP analysis were consistent with that of the AOR, the initial conditions and assumptions used were conservative, resulting in maximum peak RCS pressures, and peak pressures did not exceed the P-T limits, the NRC staff determined that the EPU LTOP analysis was acceptable, and that the current TS PORV setpoint (490 psia), the current TS SDC system relief valve setpoint (350 psia), LTOP enable temperatures, minimum cold leg temperatures for PORV use, and allowable coolddown rates would provide adequate margin from the P-T limits specified in TS 3/4.4.9 for the limiting transients.

Although the LTOP setpoints are unchanged for the EPU, reactor vessel neutron fluence is an input to the reactor vessel material evaluations that determine the setpoints. The reactor vessel neutron fluence analysis could be affected by a significant change in core operation. Since fluence calculations, as stated in licensing report Section 2.1.1.2.2 (Reference 2), were carried out based on the guidance specified in RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," the NRC staff determined that the fluence calculations were performed in a manner acceptable to the NRC staff. The EPU fluence analysis used more recent power histories that enabled removal of excess conservatism from the pre-EPU 60-year fluence analysis, while adding a 10 percent factor of conservatism to the EPU fluence projections beginning with Cycle 23. Also, the licensee used the end of life fluence values to calculate adjusted reference temperature (ART) values as described in licensing report Section 2.1.2. For the P-T limit curves acceptance criteria, they were developed in accordance with 10 CFR Part 50 Appendix G. The period of applicability after implementation of the EPU was determined based on the EPU ART projections. When the licensee evaluated the effects of the EPU on the applicability of the pre-EPU P-T limits, it compared the ART values for the current licensing basis with the ART values after the EPU. The results discussed in licensing report Section 2.1.2.2.5 showed that the current P-T limited based on pre-EPU 55 EFPY remain valid for about 47 EPFY (i.e., the limits will bound the EPU limits through that time).

Because (1) the requested EPU did not affect the LTOP limiting conditions for operation, and (2) the result of the fluence calculations providing input to the LTOP analyses remained bounding of the EPU core design for fluence values at 47 EFPY levels, the NRC staff determined that the requested EPU was acceptable with respect to LTOP.

Conclusion

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

2.8.4.5 Shudown Cooling System

Regulatory Evaluation

The RHR system, referred to as the SDC system at St. Lucie 2, is used to cool down the RCS following shutdown. The RHR system is a low pressure system which takes over the shutdown cooling function when the RCS temperature is reduced to SDC entry conditions. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the SDC 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 such sharing will not significantly impair the ability of the SSCs to perform their safety functions; and

(3) GDC 34, which specifies the requirements for RHR systems.

Specific review criteria are contained in SRP Section 5.4.7 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The St. Lucie 2 SDC system is described in FSAR Section 5.4.7. The EPU increases the residual heat generated in the core during normal cooldown, refueling operations, and accident conditions. In support of its EPU application, the licensee performed a plant cooldown analysis at EPU conditions and discussed the analysis in licensing report Section 2.8.4.4 and the licensee's response to RAI SRXB-47 (References 11; 51). The NRC staff has reviewed the plant cooldown analysis and the associated RAI response, and provided the following evaluation.

The licensee performed plant cooldown analysis using an assumed uprated power level of 3020 MWt to demonstrate that the SDC and CCW systems continue to comply with their design basis functional requirements and performance criteria for plant cooldown under the proposed EPU conditions. The cooldown analysis was performed using methods that were consistent with that used in the AOR.

The analysis considered three cases: (1) normal cooldown; (2) emergency cooldown; and (3) 10 CFR Part 50 Appendix R cooldown. For all cases, the analysis used the following assumptions:

1. The SDC heat exchanger data assumed design fouling factor and design tube plugging of 10 percent. This assumption increased the cooldown time compared with that based on the full SDC heat exchanger effective area, and thus, was conservative.

2. The decay heat model was based on the ANS 1979 decay heat standard to cover EPU operating conditions.

3. Replacement SG metal mass and water volume were included in the RCS metal heat capacity and water volume.

4. No credit was taken for convective heat losses from piping or equipment, and

5. A minimum CCW shell side flow rate was used

The above discussed plant conditions reflected the EPU conditions, and were conservative, resulting in maximum cooling times, and thus, were acceptable.

Additional assumptions were used for each of the three cases as follows:

For Case 1- normal cooldown: (1) no single failure was assumed; (2) two trains of the SDC system were credited for plant cooldown to address the design capability in the FSAR; and (3) the SDC system was initiated 3.5 hours after shutdown.

For Case 2, emergency cooldown: (1) the worst single failure assumed was a loss of EDG, which resulted in a loss of a complete train of the SDC system; (2) one train of the SDC system was credited for cooldown; and (3) the SDC system was initiated 3.5 hours after shutdown.

The above initial conditions and assumptions used for Case 1 and 2 analysis were consistent with that of the AOR, and thus, remained acceptable.

For case 3, 10 CFR Part 50 Appendix R cooldown: (1) plant fire was assumed; (2) the worst single failure assumed was a loss of one DG, which resulted in a loss of a complete train of the SDC system; (3) one train of the SDC system was credited for cooldown; (4) the maximum CCW fluid temperature and low cooldown rate of 25 °F/hr were assumed, and (5) a sensitivity study of cooldown time was performed based on the SDC system initiating from 10 to 80 hours after shutdown.

The Case 3 analysis also credited (RAI SRXB-47 Reference 51) the following critical operator action times:

a. The RCS charging system required two hours for initiation. The assumption was consistent with the current Appendix R cooldown analysis. Since the Appendix R analysis required the RCS makeup be provided within 1 hour, the assumption delay time of 2 hours to initiate charging was conservative.

b. The plant required an additional 2 hours to align for plant cooldown. This assumption was consistent with the current Appendix R analysis. An additional 2 hours (for 4 hours total) in delay of cooldown initiation was consistent the SRP BTP 5-4.

c. The maximum cooldown rate was 25 °F/hr. Although two ADVs per SG were available, only one ADV and one SG were used for cooldown. The cooldown rate based on one ADV was initially limited to 25 °F/hr. As the RCS temperatures decreased, the ADV could not maintain this cooldown rate. Accordingly, the EPU analysis assumed that the cooldown rate decreased over time as a function of valve capacity to a minimum value of 1 °F/hr.

The above discussed assumptions were conservative, resulting in maximum cooldown times, and therefore, were acceptable.

The results of the plant cooldown analysis at EPU conditions showed that (1) the normal plant cooldown duration to 200 °F, corresponding to the maximum temperature in cold shutdown (Mode 5), would increase by about 0.1 hours compared to pre-EPU conditions with both trains of SDC and CCW equipment in operation, and (2) the normal plant cooldown duration to 140 °F for refueling (Mode 6) would increase by 12 hours with both trains of SDC in operation. These results were achieved without violating the administrative limit on maximum cooldown rate of 75 ºF/hr. There are no acceptance criteria for these cooldown times.

For the 10 CFR Part 50, Appendix R cooldown analysis, the licensee modeled the worst-case scenario considering a LOOP, with one SG, one ADV and one train of SDC equipment in operation. The licensee’s analysis showed that at EPU conditions, the plant could reach the SDC system entry conditions (325 °F and 275 psia without exceeding the maximum cooldown rate of 25 °F/hr) in 20.35 hours. Once the SDC entry condition was achieved, an additional 7.15 hour holding time was assumed to allow for cooling of the reactor vessel upper head to saturation temperature. Based on these conservative timing assumptions, the total time to reach SDC entry conditions for Case 3 was 31.5 hours. The analysis then considered that the SDC system was placed in service assuming one train of SDC equipment available. The SDC system model was used to calculate the time required to cool the RCS to 200 °F (cold shutdown). The model calculated a cooldown time of 16.6 hours. Based on the cooldown analysis results, the total time to bring the plant to cold shutdown conditions from the initiation of the event was 48.1 hours (31.5 hours plus 16.6 hours). The NRC staff found that the results of the analysis met the 10 CFR Part 50, Appendix R requirements for the cooldown time limit of 72 hours. Specifically, Paragraph III.L.5 of Appendix R states that "… the fire damage to such equipment and systems shall be limited so that the systems can be made operable and cold shutdown can be achieved within 72-hour…" Therefore, the NRC staff determined that the cooldown analysis was acceptable.

In addition, the cooldown analysis demonstrated that the existing TS cooldown time limits would continue to be met at EPU conditions. Plant TSs require that the plant be in hot standby (Mode 3) in 6 hours and cold shutdown (Mode 5) in 36 hours with equipment required for power operation out of service. The licensee performed an analysis for two cases: (1) a case (Case 1 - normal cooldown) with two trains of SDC and CCW equipment in operation and (2) a case (Case 2 – emergency cooldown) with one SDC and CCW train in operation assuming SDC system initiation at a conservative duration following shutdown. The result showed that the cold shutdown could be achieved in 20 hours, and therefore, was acceptable.

<u>Conclusion</u>

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the SDC system. The NRC staff concluded that the licensee adequately accounted for the effects of the proposed EPU on the system and demonstrated that the SDC system will maintain its ability to cool the RCS following shutdown and provide decay heat removal. Based on these considerations, the NRC staff concluded that the SDC system would continue to meet the requirements of GDC 4, 5, and 34 following implementation of the proposed EPU. Therefore, the NRC staff found the proposed EPU acceptable with respect to the SDC system.

2.8.5 Accident and Transient Analyses

According to RS-001 (Reference 1), the NRC staff applies acceptance criteria, in its review of the accident and transient analyses in Section 2.8.5, that are based upon the GDC of 10 CFR Part 50, Appendix A.

RS-001 specifies 17 GDC that apply to the review of EPU applications for PWRs. These GDC are:

- GDC 4: Environmental and Missile Design Bases
- GDC 5: Sharing of Structures, Systems or Components
- GDC 10: Reactor Design
- GDC 15: Reactor Coolant System Design
- GDC 19: Control Room
- GDC 20: Protection System Functions
- GDC 25: Protection System Requirements for Reactivity Control Malfunctions
- GDC 26: Reactivity Control System Redundancy and Capability
- GDC 27: Combined Reactivity Control Systems Capability
- GDC 28: Reactivity Limits

GDC 29: Protection against AOOs
GDC 31: Fracture Prevention of Reactor Coolant Pressure Boundary
GDC 33: Reactor Coolant Makeup
GDC 34: Residual Heat Removal
GDC 35: Emergency Core Cooling
GDC 54: Piping Systems Penetrating Containment
GDC 62: Prevention of Criticality in Fuel Storage and Handling

GDC conformance is considered, in this EPU review, within the context of St. Lucie 2's licensing basis, and with respect to the predicted effects of the proposed power uprating in conjunction with the St. Lucie 2 plant design.

RS-001 also identifies four applicable regulations. These regulations are:

10 CFR 50.46:	Acceptance criteria for ECCSs for light-water nuclear power reactors
10 CFR 50.62(c)(4):	Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-watercooled nuclear power plants
10 CFR 50.63:	Loss of all alternating current power
10 CFR Part 50, App. K:	ECCS Evaluation Models

The licensee's compliance with these regulations is considered in the staff's review of this EPU application.

RS-001 also provides the following guidance regarding the limits of the staff's review:

> *The staff will review plants against their design bases. … The staff does not intend to impose the criteria and/or guidance in this review standard on plants whose design bases do not include these criteria and/or guidance. No backfitting is intended or approved in connection with the issuance of this review standard.*

Although the staff follows this guidance in its reviews of EPU applications, it is possible that the staff's review could require some additional information from the licensee, regarding issues that are outside the plant's design basis in order to support a conclusion of reasonable assurance that the public health and safety will not be jeopardized if the plant is operated at the proposed EPU power uprating. In such cases, the staff's actions are controlled, as always, by the requirements of the Backfit Rule (10 CFR 50.109).

The NRC staff's review of the accident and transient analyses discussed in below Section 2.8.5 was based on the information in the LAR (Reference 2) and the licensee's responses to various NRC staff's requests for additional information discussed in each pertinent subsections.

In letter dated July 23, 2012 (Reference 52) the licensee indicated that it revised the control element assembly reactivity insertion curve (referred to as "scram curve" herein) to for operation of St. Lucie 2 at the EPU. The revised scram curve showed that the new reactivities at intermediate insertions are lower than those specified in Figure 2.8.5.0-4 of (Reference 2) used in the EPU analyses for transients and accidents. In addressing the effect of the revised scram curve on the EPU analyses, the licensee performed an impact analysis and presented the results in (Reference 52). The impact analysis considered all EPU accidents and transients. For the events that were not affected by the revised scram curve, the licensee provided rationale to each event for not reanalyzing those events. For the events that were determined to have effort by using the revised scram curve, the licensee performed a reanalysis for each of those events. In the reanalysis, the licensee used identical assumptions and values of input parameters in the EPU analysis discussed in Section 2.8.5 of (Reference 2), except for the revised scram curve. The results of the reanalysis indicated that the following events were affected by the revised curve:

1. Loss of Forced Reactor Coolant Flow (LOF)

2. Locked Rotor/Sheared Shaft (LR/SS)

3. Feedwater Line Break

The revised values of safety parameters are provided in Table 4.0-1 of (Reference 52). Also, the reanalysis indicated that the primary and main steam system pressure peaks for the following events were negligibly impacted by the revised scram curve:

1. Feedwater Line Break (Peak main steam system pressure)

2. Loss of Condenser Vacuum

3. Asymmetric Steam Generator Transient

4. LOF

5. LR/SS (Peak Cladding Temperature)

6. CEA Withdrawal at Power

The changes in pressure peak are presented in Table 4.0-1 for these events. The results show that there is minor change in peak primary and main steam system pressure.

The NRC staff has reviewed the results of the impact analysis in (Reference 52) discussed above and included its evaluation in the applicable subsections of Section 2.8.5 discussed below.

2.8.5.1 Increase in Heat Removal by the Secondary System

2.8.5.1.1 Decrease in FW Temperature, Increase in FW Flow, Increase in Steam Flow, and Inadvertent Opening of a SG Relief or Safety Valve

Regulatory Evaluation

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

Technical Evaluation

This licensing report section, "Increase in Heat Removal by the Secondary System," addresses four AOOs: (1) Decrease in FW Temperature, (2) Increase in FW Flow, (3) Increase in Steam Flow, and (4) Inadvertent Opening of a SG Relief or Safety Valve. Each of these AOOs is evaluated separately.

A change in SG FW conditions that results in an increase in FW flow or a decrease in FW temperature could result in excessive heat removal from the RCS. Such changes in FW flow or FW temperature are a result of a failure of a FW control valve or FW bypass valve, failure in the FW 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 the CHF not being exceeded, pressure in the RCS and MSSS 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 SAL based on 95/95 DNB limit in the limiting fuel rods

- Increase in FW Flow

The licensee performed the analysis using the NRC-approved RETRAN code (described in WCAP-14882-P-A, ADAMS Accession No. ML093421329) for RCS response calculations. The results of RETRAN are used to determine if the DNB SALs for the excessive heat removal due to FW malfunction event are met. The analysis consists of both the full-power and no-load for HZP conditions. For the full-power case, previously identified as the limiting DNBR case, the initial reactor power, RCS pressure, and RCS average temperatures are assumed to be at their nominal values, and uncertainties in initial conditions are included in the DNBR limit as described in the RTDP documented in an NRC previously approved, WCAP-11397-P-A. For the HZP case, the analysis is performed to assess whether the shutdown margin of the CEAs is sufficient to overcome the effect of an increase in FW flow and combined reactivity feedback effect at post-trip conditions. If sufficient shutdown margin does not exist, a return-to-power will occur for a post-trip core. In the analysis, the uncertainties are included in the initial power, pressure, and RCS flow rate to maximize the potential of the return-to-power level during the transient. For both cases, the licensee assumed that the increase of FW event is caused by opening of the FW control valves to maximum capacity, resulting in a step increase to 120 percent of the nominal full power FW flow to both SGs. Other assumptions are

- The full-power pressurizer level is 63 percent indicated level, HZP is 33.1 percent. The FW enthalpy for the at-power cases is consistent with normal plant conditions at full rated thermal power and equal to 420.5 btu/lbm. The FW enthalpy assumed at HZP conditions is 210.0 btu/lbm.
- Maximum (end-of life) reactivity feedback conditions with a minimum Doppler-only power defect is assumed, thereby, maximizing the power increase. Reactor trip reactivity assuming the most reactive rod stuck out of the core is modeled for the full-power case. The most reactive rod stuck out of the core is also assumed for the HZP shutdown margin.
- The heat capacity of the RCS metal and SG shell is ignored, thereby, maximizing the temperature reduction of the RCS coolant.
- No SG tube plugging is assumed to maximize the RCS flow, which, in turn, maximizes the RCS temperature reduction.
- The reactor trips available for the consequence mitigation are: variable high power trip, low pressurizer pressure, thermal margin/low pressure, or low SG pressure.
- The FW flow resulting from a fully open control valve is terminated by the SG high-high water level signal.

The results showed that for the full-power case, the calculated minimum DNBR is above the SAL DNBR, and for the HZP case, the effects of an increased FW flow and combined reactivity feedback effect at post-trip conditions are not sufficient to overcome the shutdown margin of the CEAs, resulting in no return-to power to occur, which assure that no challenge to the minimum DNBR safety limits.

Based on the above discussion, the NRC staff found that the licensee performed the analysis for an increase in the FW flow event using an NRC-approved method with adequate assumptions and values for the input parameters, and the results of the analysis demonstrated that the consequences of this event met the acceptance criteria of SRP 15.1.2. Specifically, the calculated minimum DNBR is above the SAL DNBR. Therefore, the NRC staff concluded that analysis was acceptable.

- Decrease in FW Temperature

The licensee identified that the loss of a train of the high-pressure FW heaters was the limiting FW malfunction event resulting from a decrease in FW temperature. In the event of the loss of a train of the high-pressure FW heaters, there would be an immediate reduction in the FW temperature to the SGs. The licensee has determined that if failure of a train of the high-pressure FW heaters were to occur, the FW temperature would be reduced by no less than 341°F.

The licensee performed the analysis of the loss of a train of high-pressure FW heaters using RETRAN for RCS response calculations. The results of RETRAN are used to determine if the SAL DNBR limit for the excessive heat removal due to FW malfunction event is met. The analysis uses the same input parameters, assumptions, reactor trip signal, and acceptance criteria described above for the FW flow increase analysis with the additional assumptions:

(1) at full-power conditions, the FW enthalpy is reduced to a value corresponding to a reduced feewater temperature of 341 °F, and (2) the full-power FW flow is maintained to both SGs. The results showed for the limiting decreased FW temperature case, the calculated minimum DNBR is greater than the SAL DNBR , assuring that no fuel or cladding damage to occur.

Since the licensee performed the analysis for a decrease in the FW temperature event using a NRC-approved method with adequate assumptions and values for the input parameters, and the results of the analysis demonstrated that the consequences of this event met the acceptance criteria of SRP 15.1.1. Specifically, the calculated minimum DNBR was above the SAL DNBR. Therefore, the NRC staff concluded that analysis is acceptable.

- Increase in Steam Flow

The increase in steam flow event, an AOO, results in a power mismatch between the reactor power and SG load demand. The licensee stated that typically, a steam flow increase of no more than 10 percent of the initial value would be examined for an excess load increase and flow up to and exceeding 58 percent would be considered for a failure of the steam dump and bypass control system. This event reduces RCS temperature and pressure which, in the presence of a negative moderator temperature coefficient, can result in power increase. Without any protection system actions, this event may result in a DNB with subsequent fuel damage.

Since the steam flow from either the main steam relief or safety valve is within the range of steam flow from various sizes of the steam line break (SLB), the consequences of cooldown effects from the steam flow increase are bounded by that of the pre-trip SLB with failure of the fast bus transfer (FFBT). The increase in steam flow event would result in a steam release rate that is much lower than that produced by the double-ended steamline rupture. The former event is classified as an AOO, and the latter event is considered to be an accident. However, since both events were evaluated against the AOO acceptance criteria, it is possible to compare them, and to judge one event as encompassing or bounding the other. The licensee made this comparison and chose to evaluate only the double-ended steamline rupture, since it was previously identified as the limiting case.

As discussed in Sections 2.8.5.1.2 of this SE below, the both the pre-trip SLB with FFBT and the post-trip SLB analysis showed no DNBR below the SAL DNBR, thus meeting the acceptance criterion of SRP for the AOOs. Therefore, the NRC staff concluded that the results of an increase in steam flow event, a less limiting event than the SLB event, would meet the SRP acceptance criterion of the AOOs, and were acceptable.

- Inadvertent Opening of a SG Relief or Safety Valve

An inadvertent opening of an SG relief or safety valve, an AOO, may result in an increase in steam flow. In the presence of a negative moderator temperature coefficient, the excessive cooldown by the increased steam flow increases positive reactivity which, in turn, increases the core power level. As a result of the power increase and RCS pressure decrease, the calculated DNBRs may decrease, possibly causing fuel damage.

Since the steam flow from either the SG relief or safety valve is within the range of steam flow from various sizes of the SLB, the consequences of cooldown effects from the inadvertent opening of SG relief or safety valve are bounded by that of the SLB. As discussed in

Section 2.8.5.1.2 of this SE discussed below, the SLB analysis showed no DNBR below the SAL DNBRs, thus meeting the acceptance criterion of SRP for the AOOs. Therefore, the NRC staff concluded that the results of an inadvertent opening of SG relief or safety valve, a less limiting event than the SLB event, would meet the SRP acceptance criterion for the AOOs, and were acceptable.

Conclusion

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

2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment

Regulatory Evaluation

The steam release resulting from a rupture of a main steam pipe will result in an increase in steam flow, a reduction of coolant temperature and pressure, and an increase in core reactivity. The core reactivity increase may cause a power level increase and a decrease in shutdown margin. Reactor protection and safety systems are actuated to mitigate the transient.

The 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 responses of the reactor coolant and auxiliary systems;

(5) functional and operational characteristics of the RPS;

(6) assumed operator actions;

(7) core power excursion due to the power demand created by excessive steam flow;

(8) variables influencing neutronics; and

(9) the results of the accident analyses.

The NRC's acceptance criteria are based on:

- GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained;

- GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core;

- GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized;

- GDC 35, insofar as it requires the RCS and associated auxiliaries be designed to provide abundant emergency core cooling.

Specific review criteria are contained in SRP Section 15.1.5 and additional guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The SLB events were performed at EPU conditions. Cases were analyzed for both HFP and HZP conditions. In consistency with the analysis of record discussed in the FSAR, Chapter 15.1.5, two categories of the SLB events were analyzed: pre-trip and post-trip SLBs. The NRC staff's evaluation of the SLB analysis is discussed as follows.

2.8.5.1.2-1 Pre-Trip MSLB

Section 2.8.5.1.2.2.1 of the licensing report (Reference 2) describes the pre-trip SLB event. This analysis is supplemented by responses to NRC staff RAIs (Reference 11).

Analytical Methods

The Westinghouse computer codes RETRAN and VIPRE (documented in WCAP-14565-P-A) are used to simulate the pre-trip SLB event. These codes have been previously reviewed and approved and their application is consistent with the pre-trip SLB methodology as reflected in the latest amendment to Section 15.1.5 of the St. Lucie 2 FSAR.

Similarly, the pre-trip MSLB methodology was employed in the selection of initial conditions and assumptions that would maximize the power excursion and DNB degradation experienced during the event. Two distinct scenarios were analyzed:

1. Pre-Trip SLB with the FFBT at Reactor/Turbine Trip
2. Pre-Trip SLB with LOOP

Pre-Trip SLB with FFBT - Analytical Assumptions

For the pre-trip SLB with FFBT analysis, the assumptions include:

● The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their nominal values corresponding to EPU conditions. The RCS minimum measured flow is used to minimize the minimum DNBR. Uncertainties in initial conditions are included in the DNBR limits in accordance with the NRC-approved RTDP documented in WCAP-11397-P-A.

● A spectrum of break sizes is analyzed ranging from 0.1 ft^2 to the 6.305 ft^2 (the cross sectional area of the steam line pipe). The reactor trip signals on the setpoints of variable high power and low SG pressure are available.

● The Moody critical flow model without consideration of the piping friction losses is used to calculate the steam flow to maximize the flow rate, and thus, the cooldown effects during a SLB.

● Reactivity feedback is conservatively chosen to maximize the pre-trip power increase and thus, the heat flux. A full range of the moderator density coefficient (MDC) values from 0 to 0.43 Δk/gm/cc are considered in the analysis. The limiting MDC value is determined to be 0.3 k/gm/cc through the performed sensitivity study. This value is also used in for the less limiting pre-trip SLB with LOOP event. For the moderator temperature coefficient (MTC) and Doppler power coefficient (DPC), the most negative value specified in the TSs and the least negative curve corresponding to EOL conditions are chosen for the MTC and DPC, respectively (as discussed in Table SRXB-49-1 to 49-3 of the licensee's RAI response (Reference 11)).

● The analysis only considers the initial phase of the transient initiated from an at-power condition. Protection in this phase of the transient is provided by reactor trip.

● The results of the analysis would not be more severe as a result of control system actuation, therefore, their effects are not considered. Control systems are not credited in mitigating the consequences of the SLB.

● The FFBT at the time of turbine trip (0.0 seconds following reactor trip breaker opening is modeled). The assumption of the FFBT results in two of the RCPs coasting down. The remaining two RCPs are assumed to coast down 3 second flowing the time of reactor trip breaker opening due to the LOOP.

The NRC staff found that the seven assumptions discussed above were consistent with the first seven assumptions used in the AOR documented in the FSAR, Section 15.1.5.2. However, the last four assumptions (8 through 11) in the AOR were not included. The four assumptions contain conservatisms in the analysis in resolving the NRC staff 's concern of adequacy of the T-H modeling of core inlet flow distribution during a 2-pump coastdown conditions applicable to the SLB event with the FFBT case. In response to an NRC staff's RAI, the licensee confirmed (SRXB-58, Reference 11) that the 4 assumptions listed in the FSAR Section 15.1.5.2 remained applicable. The assumptions are as follows:

● In RETRAN, the transient nuclear power prediction does not credit a decrease in rod drop time due to a core flow reduction experienced during the two-pump coastdown.

● In RETRAN, the transient nuclear power prediction assumes a minimum scram reactivity worth based upon the most bottom-peaked axial power distribution. In VIPRE, the DNBR calculations are based on top-peak axial power distribution.

● In VIPRE, the peak power assembly with the peak rod at the radial peaking factor (F_r) design limit and a low peak-to-average power ratio is model at the core location corresponding to the minimum flow assembly.

● In estimating the number of rods in DNB, the most limiting channel's local conditions at the time of minimum DNBR are used to back-calculate F_r corresponding to the DNB SAFDLs. By presuming that every fuel pin in the core with a pin power above this peaking limit experiences DNB (via the pin census data), the entire core is modeled at the limiting channel conditions.

Pre-Trip SLB with FFBT - Analytical Results

The inside containment pre-trip SLB with FFBT analysis was performed on a spectrum of break sizes ranging from 0.1 ft^2 to 6.305 ft^2 (the maximum area of steam line) and a spectrum of MDCs ranging from 0.0 k/gm/cc to 0.43 k/gm/cc. The break was modeled on steamline upstream of the MSIV, which was identified in the AOR as the worst location preventing the affected SG from being isolated by the MSIV closure. The results showed that no reactor trip would occur for cases modeling the smallest break sizes. For the small breaks, the power would reach equilibrium based on the increasing steam releases. As break size increased, the power increased until the reactor tripped on the variable high power trip (VHPT) signal. The spectrum study showed that the limiting case was the 1.910 ft^2 break with a MDC of 0.30 k/gm/cc, resulting in the highest peak heat flux and lowest DBNR.

Table 2.8.5.1.2-4 of the licensing report (Reference 2) shows the results of the calculated values of DNBRs and peak linear heat rates. This table indicates that the peak heat linear heat rate is bounded by the safety limit and the hot channel minimum DNBR remains above the 95/95 DNB limit for the duration of the event, thus, assuring no fuel rod failures due to high linear heat rate and DNB. Based upon the conservative nature of the composite event (superimposing the 2-RCP coastdown flow on the peak power excursion SLB case) and the conservatism identified above, the NRC staff concluded that the analysis of the pre-trip SLB with FFBT event was acceptable.

Pre-Trip SLB with LOOP - Analytical Assumptions

For the pre-trip SLB with LOOP analysis, the assumptions include:

● The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their EPU values. The RCS minimum measured flow is used. Uncertainties in initial conditions are included in the DNBR limits in accordance with the NRC-approved RTDP documented in WCAP-11397-P-A.

● A break size of 1.910 ft^2, corresponding to the maximum flow area of the SG integral flow restrictors in the replacement SGs, is analyzed. The analyzed break size was confirmed to be the most limiting by the licensee's FFBT case break size sensitivity study and then examined for the LOOP case.

● The Moody critical flow model without consideration of the piping friction losses is used to calculate the steam flow rate during an SLB event.

● Reactivity feedback is conservatively chosen to maximize the pre-trip power increase and thus, the heat flux. The MDC spectrum scoping performed for the limiting pre-trip SLB with

FFBT event identified a limiting MDC value to be 0.3 k/gm/cc. This value is also used for less limiting pre-trip SLB with LOOP event. For the MTC and, the most negative value specified in the TS and the least negative curve corresponding to EOL conditions are chosen, respectively (as discussed in Tables SRXB-49-1 to 49-3 of Reference 11).

● A conservative low trip reactivity value is used to minimize the effect of the control rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR calculation. The reactivity value of the control rod insertion is based on the assumption that the highest worth CEA is stuck in its fully withdrawn position.

● The analysis only considers the initial phase of the transient initiated from an at-power condition. Reactor trip is provided by a low RCS flow trip with a conservative setpoint using harsh environment uncertainty.

● The results of the analysis would not be more severe as a result of control system actuation, therefore, their effects are not considered. Control systems are not credited in mitigating the consequences of the SLB.

● The analysis assumes that a LOOP occurs concurrent with the SLB causing the four RCPs to start coastdown prior to control rod motion. The statepoints from this case, which include power, pressure, temperature, and core flow, are used to as input to VIPRE to determine the DNBRs.

● For the SLB with LOOP analysis, the licensee uses the fuel rod failure criteria specified in SRP Chapter 15.1.5 (Revision 3), which states that "the potential for core damage is evaluated on the basis that is acceptable if the minimum DNBR remains above 95/95 DNBR limit for PWRs based on acceptable correlations. If the DNBR falls below these values, fuel failures (rod perforation) must be assumed for all rods that do not meet these criteria…Any fuel damage calculated to occur must be of sufficient limited extent that the core will remain in place and geometrically intact with no loss of core cooling capability."

Pre-Trip SLB with LOOP Analysis - Analytical Results

The SLB with LOOP was analyzed for the 1.910 ft^2 break with a MDC of 0.30 k/gm/cc case, which is the same break size identified as the limiting case from the sensitivity study for the pre-trip SLB with FFBT event. Table 2.8.5.1.2-4 of the licensing report (Reference 2) showed the results of the calculated values of DNBRs and peak linear heat rates. This table indicated that the calculated minimum DNBR and peak linear heat rate for the pre-trip SLB inside containment with LOOP case met the DNB and fuel centerline melting criteria. Furthermore, the pre-trip SLB outside containment with LOOP analysis is bounded by the SLB inside containment with LOOP case because the same trip functions credited for the inside containment break are available for the outside containment break without hash environment uncertainties.

Based on the review of the pre-trip SLB analysis, the NRC staff found that for all events analyzed, there were no DNB and fuel centerline melting, which assure that coolable geometry is maintained. Site boundary doses were maintained within acceptable limits by demonstrating that the amount of fuel rod failures (due to DNB) did not exceed the assumption in the docketed dose calculation. As discussed in Section 2.9.2 of the licensing report (Reference 2), "Radiological Consequences Analysis Using Alternative Source Terms (AST)", the rods-in-DNB for the inside and outside containment breaks for EPU were 21 percent and 1.2 percent, respectively. Therefore, the NRC staff determined that the failed fuel rods due to DNB for the pre-trip SLB events were well within the assumed values used in the acceptable EPU dose analysis. The bases of the NRC acceptance of the dose calculation are discussed in Section 2.9.2 of this report.

The NRC staff determined that the analysis met the guidance in SRP 15.1.5, since the analysis showed that fuel geometry for core cooling would be maintained and the calculated rods-in-DNB were bounded by the assumed values used in the acceptable dose calculation, and thus concluded that the results of the analysis for the limiting pre-trip SLB events were acceptable.

2.8.5.1.2-2 Post-Trip SLB

An SLB event results in an uncontrolled increase in steam flow released from the SGs. The steam release during an SLB causes a decrease in the RCS temperature and SG pressure. In the presence of a negative MTC, the RCS temperature decrease results in an addition of positive reactivity. If the added reactivity is greater than the control rod worth of the reactor trip and the boron injection from the safety injection system, the core would return to criticality for post-trip SLB conditions, which may result in fuel failures. The licensee's analysis discussed in Section 2.8.5.1.2.2.2 of the licensing report (Reference 2) is to show that the post-trip SLB analysis meets the SRP 15.1.5 guidance that applicable dose limits are not violated and a coolable geometry is maintained. The post-trip SLB analysis is supplemented by responses to NRC staff' RAIs (Reference 11).

Analytical Methods

The licensee analyzed the post-trip SLB event using three computer codes: RETRAN, ANC (described in WCAP-10965-P-A, ADAMS Accession No. ML080630392) and VIPRE. RETRAN calculates transient values of key plant parameters, such as core average heat flux, core pressure, core inlet temperature, and RCS flow rate, identified as statepoints. ANC determines the peaking factors associated with the return-to-power in the region of the stuck CEA and verifying the RETRAN transient prediction of the average core power and reactivity. VIPRE calculates the minimum DNBR based on W-3 DNB correlation with input of the RETRAN-calculated statpoints and the ANC-calculated peaking factors. The peak linear heat rate is based on the result of the ANC analysis. The NRC staff found these codes were previously reviewed and approved, and their application was consistent with the post-trip SLB methodology used in the AOR discussed in Section 15.1.6 of the St. Lucie 2 FSAR. Therefore, the NRC staff concluded that the use of the codes and methodology continued to be acceptable.

Analytical Assumptions

The licensee analyzed a double-ended rupture at a main SG outlet, initiated from HZP conditions with no decay heat in combination of the offsite power available, which was identified as the limiting post-SLB case discussed in the AOR. Because each steam line is connected to a SG through a exit nozzle with a integral flow restrictor with a 1.91 ft^2 throat area, any rupture with a break size greater than 1.91 ft^2 break, will have the same effect on the system as a 1.91 ft^2 break and therefore, the limiting break area of 1.91 ft^2 was assumed in the analysis. The break size discussed above is the major deviation from the AOR, which assume a break size of 6.305 ft^2 for the affected SG representing the maximum flow area of SG outlet nozzle, and a break size of 2.27 ft^2 for the intact SG representing the flow area of inline flow restrictor. The most limiting single failure was assumed to be a failure of one HPSI train, which is the limiting single failure identified in the AOR.

Similarly, the FSAR post-trip SLB methodology was used in the selection of initial conditions and assumptions that would maximize the return-to-power experienced during the event. In consistency with the AOR in FSAR Chapter 15.1.5, the licensee analyzed the limiting scenario, the double-ended rupture (DER) of a main steam line at HZP subcritical conditions (corresponding to EOL shutdown margin requirements) with offsite power available. The DER of the steamline was modeled to occur at the SG outlet nozzle and steamline. The initial conditions corresponded to a subcritical reactor, an initial RV average temperature at the no-load value and no core decay heat. The NRC staff found that these assumptions were consistent with the AOR assumptions, and they were conservative, compared to hot full-power, for a SLB event because the resulting RCS cooldown would not need to remove any latent heat. Also the SG water inventory was greatest at no-load conditions, which would increase the capability for cooling the RCS. Thus, the analysis of the HZP case would bound the case of a post-trip analysis from HFP. Also, the case assuming offsite power available was identified in the AOR to be more severe than the case with LOOP, since the presence of forced RCS flow would aid the core cooldown. In addition, in order to maximize the overcooling effect, the analysis used the following assumptions:

- The end-of-life shutdown margin corresponding to no-load, equilibrium xenon conditions is assumed.

- The most reactive CEA is in the fully withdrawn position after reactor trip.

- The Moody critical flow model, without consideration of the piping friction losses, is used to calculate the steam flow.

- No moisture is assumed in the blowdown steam.

- The closure of the MSIV of the intact loop is assumed to complete at the TS value of 6.75 seconds after receipt of a low SG pressure signal at 487 psia (which corresponds to the TS value of 600 psia with harsh environment uncertainties) from the same loop.

- The safety injection signal is actuated at the low pressurizer pressure setpoint of 1638 psia (which represents a TS setpoint of 1736 psia with harsh environment uncertainties).

- The minimum capacity for the injection of boric acid solution, corresponding to the most limiting active single failure in the safety injection system, is assumed. Boric acid solution from the RWT, with a minimum concentration of 1720 ppm (which is lower than the minimum TS value of 1900 ppm), and a minimum temperature of 51 °F (which is lower than the minimum TS value of 55 °F).

- Main FW flow corresponding to the nominal value at 100 percent power is assumed to initiate coincident with the postulated SLB event.

- A minimum SG tube plugging level of 0 percent is assumed to maximize the heat transfer capabilities of the SGs.

- Four RCPs are initially operating with the thermal design flow 375,000 gpm to minimize the minimum DNBR.

The analysis assumed that fuel failures (rod perforation) would occur for all rods that did not meet the criteria requiring the minimum DNBR for the intact rods maintaining above 95/95 DNBR limit based on acceptable correlations. The NRC staff found that this assumption was consistent with the guidance in SRP Section 15.1.5 and, therefore concluded that it was acceptable.

Analytical Results

Figure 2.8.5.1.2-19 through Figure 2.8.5.1.2-25 of the licensing report showed the results of the key transient parameters for the limiting post-trip SLB event. Figure 2.8.5.1.2-23 indicated that the cold leg temperature (CLT) decreased rapidly after the SLB initiation. For the affected SG, at about 25 seconds the CLT suddenly increased until 30 seconds, following with a decrease of 8°F. From 38 to 41 seconds, the CLT increased by about 2°F, following with a continued decrease until 93 seconds when the pressurizer was refilled with water. During the review, the NRC staff requested the licensee to explain T-H phenomena for the identified CLT increases during the above period.

In its response to RAI SRXB-57 (Reference 11), the licensee stated that the CLT increases during the period of 25 to 41 seconds were caused by a decrease in heat transfer from the primary to the secondary side due to a vapor bubble formation in the lower downcomer and lower bundle regions. The licensee performed a sensitivity study to eliminate the vapor lock condition, thereby improving the primary to secondary heat transfer and increasing the RCS cooldown. The study showed that when there was no vapor lock, the event (Figure SRXB-57-1of Reference 11) was extended beyond that noted in the Figure 2.8.5.1.2-23 of the licensing report (Reference 2) and the maximum heat flux was 6.0 percent (Figure SRXB-55-1 of Reference 11), compared to 5.6 percent for the maximum heat flux from the EPU analysis. The EPU analysis calculated a minimum DNBR of 4.307 whereas the sensitivity study calculated a minimum DNBR of 3.611. Both cases showed that the DNBR limit of 1.30 was met. The licensing report (Table 2.8.5.1.2-6 of Reference 2) also showed that for the limiting SLB event, the calculated peak linear heat rate was 7.25 kW/ft, which is well within the safety fuel melting limit of 22 kW/ft.

Based on the review of the post-trip SLB analysis discussed above, the NRC staff fi ound that for the limiting post-trip SLB case, there were no fuel failures either due to DNB or fuel melting. These results would assure that (1) coolable geometry was maintained, and (2) the rods-in-DNB were within the limits of 21 percent and 1.2 percent assumed in the acceptable EPU dose analysis for the respective inside and outside containment SLB breaks discussed in the licensing report (Section 2.9.2 of Reference 2), “Radiological Consequences Analysis Using Alternative Source Terms (AST)”. The NRC staff found that the results of the post-trip SLB analysis met the acceptance criteria for the SLB analysis and were consistent with the SRP Section 15.1.5 guidance, and therefore, determined the analysis was acceptable. The bases of the NRC acceptance of the EPU dose calculation are discussed in Section 2.9.2 of this report.

Conclusion

The NRC staff has reviewed the licensee’s analyses of steam system piping failure 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 nonbrittle manner, the probability of a propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 27, 28, 31, and 35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to steam system piping failures.

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 Regulatory Failure

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. This event is classified as an AOO, or an ANS Condition II event.

The NRC staff's review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses. The NRC's acceptance criteria are based on:

(1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;

(2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and

(3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

Specific review criteria are contained in SRP Section 15.2.1-5, and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

A major loss of load can result from either a loss-of-external electrical load or from a turbine trip (TT) from full power without a direct reactor trip. Signals such as generator trip, low condenser vacuum (LOCV), manual trip and reactor trip may initiate a TT. Following a TT, the turbine stop valves rapidly close, and steam flow to the turbine abruptly stops. The loss of steam flow results in a rapid increase in secondary system pressure, and temperature, as well as a reduction of the heat transfer rate in the SGs, which, in turn, causes the RCS primary system P-T to rise. The acceptance criteria applicable to these AOOs are that (1) DBNR safety limit is not exceeded, (2) maximum pressure in the RCS and MSSS are maintained below 110 percent of the design pressures values, and (3) the events do not develop into a more serious plant condition without the occurrence of another, independent fault. Specific review criteria are provided in SRP Section 15.2.1-5.

The licensee analyzed the LOCV event as a limiting loss of load event assuming a TT from full power with a simultaneous loss of FW to both SGs due to low suction pressure on the FW pumps. In addition, the licensee assumed that the ADVs and the steam dump and bypass system valves were unavailable, which minimizes the amount of cooling and maximizes the RCS and secondary peak pressure. Because the licensee assumed that steam dump and FW flow are unavailable in the LOCV analysis, no additional adverse effects will result for the TT or loss of load event. Therefore, the LOCV analysis bounds the TT and loss of load events. For the LOCV event, the reactor would trip on the high pressurizer pressure signal, or the thermal margin/low pressure trip signal.

The licensee performed the analysis of the LOCV using NRC- approved codes: RRETRAN for the transient response calculation and VIPRE for the DNBR calculations. The licensee analyzed three cases for a LOCV event from full power at power uprate conditions:

(1) A minimum DNBR case with automatic pressurizer pressure control and maximum SG tube plugging (SGTP);

(2) A maximum MSSS pressure case with automatic pressurizer pressure control and minimum SGTP; and

(3) A maximum RCS pressure case with no pressurizer pressure controland maximum SGTP.

For the minimum DNBR case, Case (1), automatic pressurizer control was modeled. The pressurizer pressure control will actuate the pressurizer spray that causes the pressurizer pressure to decrease, and the lower safety valve setpoint will open the safety valves at a lower pressure and limit the pressure increase, resulting in lower DNBRs. The assumed maximum SGTP would reduce heat transfer from the RCS primary system to secondary system, resulting in an increase in RCS temperature and thus, a decrease in the DNBRs. In the DNBR calculations, the RTDP documented in WCAP-11397-P-A was used. The initial reactor power and RCS temperature were assumed to be at values consistent with 100 percent of rated thermal power and nominal pump heat. The initial RCS flow rate was assumed to be the minimum measured flow rate and the initial RCS pressure was assumed to be the minimum value allowed by the TS in order to minimize the minimum DNBR. The uncertainties in initial conditions are included in the DNBR limit as described in the RTDP.

For the maximum MSSS pressure case, Case (2), the operation of pressurizer sprays and PORVs was also assumed, in order to limit the RCS pressurization, and delay the reactor trip from the high pressurizer pressure signal, resulting in a conservatively high calculated peak secondary side pressure. For the maximum RCS pressure case, Case (3), the operation of pressurizer sprays and PORVs was not assumed to conservatively maximize the RCS pressure increase. For Cases (2) and (3), the NRC-approved Standard Thermal Design Procedure (STDP) was used. The STDP includes uncertainties on NSSS power, reactor coolant flow, RCS temperature and pressure applied in the most conservative direction to determine the initial plant conditions to maximize the peak RCS and MSSS pressure during the transient.

The LOCV event was analyzed with minimum reactivity feedback at beginning of the core life. All cases used the least negative Doppler power coefficient curve for 100 percent power shown in Figure 2.8.5.0-5 of the licensing report and a 0 ppm/°F moderator temperature coefficient (per Table SRXB-49-3 of Reference 11). These reactivity conditions were selected based on the conditions that the reactor power was maintained at the full power condition until the time of reactor trip, which results in a lower minimum DNBR and higher RCS and MSSS pressures. Therefore, the assumptions are acceptable.

In all cases, the PSVs were assumed to be operable and included the maximum negative safety setpoint tolerance (-3 percent) for the minimum DNBR case, and the maximum positive safety valve setpoint tolerance (+3 percent) for the primary over-pressurization case. This assumption was consistent with the proposed TS LCO 3.4.4, which changes the tolerance $\pm$ 2 percent to $\pm$ 3 percent. The MSSS model for all case included the maximum safety valve setpoint tolerance of +3 percent (per Table SRXB-39-1 of Reference 53). This assumption will delay opening of the MSSV and reduce heat removal from SGs, resulting in a higher SG pressure, and an increase in the RCS P-T, which cause a decrease in DNBR. This assumption is consistent with the upper bound (+3 percent) of tolerance of the lift setpoints for the MSSVs in the proposed TS Table 3.7-2 and is acceptable. Maximum (10 percent) SGTP was assumed in the minimum DNBR case and peak RCS pressure cases since it maximized the primary side temperature transient following event initiation. For the maximum MSSS pressure case, minimum (zero percent) SGTP was assumed since this assumption maximized the primary-to-secondary heat transfer and maximized the initial SG pressure, resulting a slightly higher MSSS pressure increase. In addition, Case (2) and (3) were also analyzed to verify that the event could not become a small break LOCA, by filling the pressurizer, discharging water through the PORVs and causing a PORV to stick open. This demonstrated by showing that the pressurizer does not become water-solid at any time during the transient. The PORVs, therefore, would not have to discharge water.

The results of these three analyses (in Tables 2.8.5.2.1-4 through 2.8.5.2.1-6 of the licensing report) indicated that, in each case, the reactor was tripped on the high pressurizer pressure signal. In Case (1), the minimum DNBR was 2.23, which is within the DNBR SAL of 1.42. In Case (2), the maximum MSSS pressure was 1094.75 psia, which is within the MSSS pressure limit of 1100 psia. In Case (3), the maximum RCS pressure was less than 2702 psia, which is within the RCS pressure limit of 2750 psia.

The analysis results also indicated that peak pressurizer water volume attained would not be sufficient to fill the pressurizer. The licensee indicated that the initial pressure water level used in the LOCV analysis was 66 percent of the span, which represented the normal pressurizer level of 63 percent span plus 3 percent. This value was consistent with the AOR documented in FSAR Section 15.2.3 and standard Westinghouse methodology for the LOCV event. During the review, the NRC staff noted that TS 3.4.3 allowed an upper limit of 68 percent for the pressurizer water level. When an uncertainty of 3 percent was added, the TS allowed upper pressurizer level would be 71 percent. Higher initial water level could result in a smaller margin to pressurizer overfill and the EPU analysis assuming an initial pressurizer water level of 66 percent would not be conservative. In addressing this concern, the licensee provided its RAI SRXB-48 response (Reference 11). The licensee indicated that the maximum pressurizer water volume observed during a LOCV event was slightly less than 1100 ft^3. There were over 400 ft^3 margin to the total pressurizer volume of 1519 ft^3. The difference between 71 percent and 66 percent span was approximately 76 ft^3 of additional water volume. If the maximum initial value of 71 percent span was used, over 300 ft^3 (400 – 76) margin would still remain. The NRC staff agreed that the RAI response provided additional evidence that the pessurizer overfill would not occur during the LOCV event. The licensee also indicated that "initiating from 66 percent as opposed to 71 percent would delay the reactor trip and provide a longer increase in pressure for the LOCV event, ultimately leading to a higher observed pressurizer pressure." At the NRC staff request, the licensee quantified the impact of the initial water level on the peak pressure. In its response (page 5 of Attachment 1 to Reference 50), the licensee identified that the impact from initiating at 71 percent as opposed to 60 percent span (representing nominal value of 63 percent minus 3 percent uncertainty) would increase the primary peak pressure by approximately 1 psi. When this pressure difference was added to the maximum RCS pressure of less than 2802 psia, the resulting peak primary pressure of less than 2703 psia still remained within the limit of 2750 psia, and thus, was acceptable. Licensing report Table 2.8.5.2.1-7 showed the result of three inoperable MSSV cases analyzed for secondary overpressure. For all cases the peak SG secondary pressures were within the pressure design limit of 1100 psia.

During the review, the NRC staff noted that the analysis of the LOCV event covered a short duration of the transient. The analysis identified the first pressure peak; however, the event duration did not indicate the impact of AFW flow addition and the second pressure peak that could be associated with AFW initiation. In addressing the NRC staff's concern, the licensee reanalyzed the LOCV event by extending the end time of the event past the point of AFW initiation where the second peak could occur and presented the results on pages 6 through 13 of Attachment 1 to FPL letter L-2012-150 (Reference 50). The analysis was performed with the current LOCV methodology. Table LOCV-1 of L-2012-150 (Reference 50) provided a summary of the initial conditions used in the LOCV analysis. The values used for key parameters were to maximize the peak pressure and were conservative. The parameters included core power, RCS flow rate, RV average temperature, setpoints of the PSV and MSSV, reactor trip point for the HPP trip, and the decay heat model. Two motor driven AFW pumps were assumed available with the flow rate of 275 gpm for each AFW pump. The AFW actuation setpoint of 14.5 percent NR was assumed to be based on the low SG nominal value minus uncertainty and was lower than the minimum available value of 18 percent NR specified in TS Table 3.3-4, Functional Unit 7.c for the low SG level to actuate AFW. The use of the lower AFW actuation setpoint delayed the heat removal and would result in an increased peak pressure, and therefore, was conservative and acceptable.

Figures LOCV-1 through LOCV-5 provided the results for core power, RCS pressure, SG pressure, SG mass and AFW flow and showed that there was no second pressure peak during the transient. The sequence of events provided in Table LOCV-2 indicated that the peak primary pressure remained the same as that listed in licensing report Table 2.8.5.2.1-2.

The results of the reanalysis also demonstrated that the MSSVs were adequately sized to provide sufficient cooling to offset the decay generated. Therefore, the NRC staff concluded that the MSSV relief capacity was sufficient to preclude any second pressure peaks during the transient and the primary and secondary side peak pressures listed in licensing report Table 2.8.4.2.1-2 and licensing report Table 2.8.4.2.1-3 remained bounding.

Also, the licensee performed an analysis for the loss of normal FW (LONF) event and presented the results on pages14 through 20 of Attachment 1 to L-2012-150 (Reference 50). Table LONF-1 of L-2012-150 (Reference 50) provided a summary of the initial conditions used in the LONF analysis. The values used for all key parameters were the same as that listed in Table LOCV-1 used for the LOCV reanalysis. In addition, the pressurizer heater was assumed to be available. Credit of the pressurizer heater increased the energy in the pressurizer and would result in an increase in the primary peak pressure, and therefore, was conservative and acceptable.

Figures LONF-1 through LONF-5 provided the results for core power, RCS pressure, SG pressure, SG mass and AFW flow and showed that there was a second pressure peak during the transient. The sequence of events provided in Table LONF-2 indicated that the peak primary pressure was 2627.91 psia, which was bounded by the LOCV results in Table LOCV-2

Based on the above discussion of the analysis of the LOCV and LONF events, the NRC staff concluded that the limiting LOCV overpressure case remained valid.

Conclusion

The NRC staff has reviewed the licensee's analyses of the limiting loss of external electric load event, a LOCV, and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff found the licensee demonstrated the minimum DNBR will remain above the SAL and pressures in the RCS and MSSS will remain below 110 percent of their respective design pressure values for the proposed power uprate. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff determines that the proposed EPU is acceptable with respect to the LOCV event discussed above.

2.8.5.2.2 Loss of Nonemergency AC Power to the Station Auxiliaries

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 RCPs. This causes a flow coastdown and a decrease in heat removal by the secondary system, a turbine trip, an increase in P-T of the reactor coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. This event is classified as an AOO, or an ANS Condition II event. The NRC's acceptance criteria are based on:

(1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;

(2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and

(3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

Specific review criteria are contained in SRP Section 15.2.6 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The LOAC, an AOO, cuts off all power to the station auxiliaries and trips RCPs. The reactor and turbine trip, the RCPs coast down, and RCS P-T rise as 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 licensee indicated that with respect to a decrease in DNBRs, the LOAC event is bounded by the loss of forced reactor coolant flow (LOF) event (Section 2.8.5.3.1 of Reference 2). For the LOAC event, the RCPs will coast down immediately in addition to the loss of FW flow. This event is identical to the LOF event except that the reduction in FW flow will reduce the cooling of the RCS primary system which, in turn, results in an increased RCS pressure, thereby increasing the DNBR in comparison to the LOF analysis. The increase in SG primary side exit temperature will not have sufficient time to transport to the core inlet to adversely affect the DNBR calculation. Therefore, the minimum DNBR for the LOAC event is bounded by that of the LOF event.

With respect to RCS and MSSS over-pressurization, the LOCV event discussed in Section 2.8.5.2.1 of the licensing report (Reference 2) is more limiting than the LOAC event. Both LOCV and LOAC result in a TT; however, FW flow instantaneously terminates following LOCV whereas it ramps down following TT that occurs at the initiation of the LOAC event. The net effect of the TT and loss of normal FW flow for the LOCV event is a total loss of RCS secondary system heat sink, which results in the greatest challenge to RCS primary and secondary system pressurization. In addition, a complete OF will occur at the initiation of the LOAC event. The LOF results in an earlier reactor trip (on a low RCP flow trip signal) for the LOAC event compared to the reactor trip (on a high pressurizer pressure trip signal) for the LOCV. The earlier reactor trip results in a less primary-to-secondary heat imbalance and hence a lower peak RCS and MSSS pressure for the LOAC event.

Based on the above discussion, the NRC staff agreed with the licensee that the consequences of the LOAC event would be bounded by the analyses of the LOF and LOCV events, which were found acceptable by the NRC staff (as discussed in Sections 2.8.5.3.1 and 2.8.5.2.1 of this SER, respectively). Therefore, the NRC staff concluded that the consequences of the LOAC event were acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of non-emergency AC power to station auxiliaries event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using an acceptable evaluation. The staff further concludes that the licensee has demonstrated that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the staff concludes that the plant will continue to meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the loss of non-emergency AC power to station auxiliaries event.

2.8.5.2.3 Loss of Normal FW Flow

Regulatory Evaluation

A LONF could occur from (1) breaks in the main FW system piping up steam of the main feddwater check valves, (2) failure or trip of the main FW pumps, including of loss power for motor driven feedtwater pumps, and (3) spurious closure of main FW isolation valves or main

FW regulating valves. Loss of FW flow results in an increase in reactor coolant temperature and pressure which eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a loss of normal FW flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient.

The NRC staff's review covered: (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on:

(1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;

(2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and

(3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

Specific review criteria are contained in SRP Section 15.2.7 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The LONF, an AOO, results in a reduction in a reduction in the SG water level, which may lead to a reactor trip and AFW actuation on a low SG water level signal. Following the reactor trip, the rate of heat generation in the RCS may exceed the heat removal capability of the secondary system, and result in an increase in the SG pressure and an increase in the RCS pressure. This trend continues until the RCS heat generation rate falls below the secondary heat capability. Afterward, the RCS primary P-T begin to decrease, thereby terminating the transient in terms of potential challenge to the acceptable safety criteria.

The licensee indicated that with respect to a decrease in DNBRs, the LONF event is bounded by the LOF event discussed in Section 2.8.5.3.1 of the licensing report (Reference 2). For the LONF event, the RCS temperature increases slightly prior to reactor trip with no appreciable increase in the core power while the RCS flow is maintained. The minimum DNBR for the LONF event is bounded by that of the LOF event since the effect of the reduction in the RCS flow is more significant than the effect of the increase in the RCS temperature observed for the LONF event prior to reactor trip

With respect to RCS and MSSS over-pressurization, the LOCV event discussed in Section 2.8.5.2.1 of the licensing report (Reference 2) will be more limiting than the LONF event. The LOCV event results in the termination of main steam flow prior to reactor trip in addition to the total loss of normal FW flow. The termination of the steam flow at the initiation of the LOCV event aggravates RCS pressurization of the RCS pressure compared to the LONF event. The net result for the LOCV event is a total loss of the secondary heat sink, which results in the greatest challenge to RCS and MSSS over-pressurization.

Based on the above discussion, the NRC staff agreed with the licensee that the consequences of the LONF event were bounded by the analyses of the LOF and LOCV events, which were found acceptable by the NRC staff (as discussed in Sections 2.8.5.3.1 and 2.8.5.2.1 of this evaluation, respectively). Therefore, the staff concluded that the consequences of the LONF event were acceptable.

Long-term Cooling Analysis for the LOAC, LONF and FLB Events

Licensing report Sections 2.8.5.2.2, 2.8.5.2.3 and 2.8.5.2.4 indicated that the long-term-cooling (LTC) analysis for the LOAC, LONF, and FLB events were presented in licensing report Section 2.5.4.5. However, licensing report Section 2.5.4.5 provided acceptance criteria, but not the details for the LTC analysis at EPU conditions. In response to the NRC staff's RAI SRXB-60 (Reference 11), the licensee provided the LTC analysis that was used to support the adequacy of the AFW system for operation at EPU conditions.

In the response, the licensee indicated that the LTC analysis was performed in accordance with the FSAR Section 10.4.9A, which specified the following AFW design bases for LTC:

1. Sufficient capability exists for removal of decay heat from the reactor core;

2. The ability to reduce RCS temperatures to entry temperatures for activating the SDC system; and

3. Prevent lifting of the PSVs when considered in conjunction with the PORVs.

Item 1 above is satisfied by assuring that the SGs do not loose heat transfer capability during the event and are able to reduce the RCS temperature. As long as inventory remains in the SGs, the AFW system is capable of providing sufficient capability for decay heat removal. Item 2 above is satisfied by demonstrating that subcooling margin is maintained throughout the entire event and inventory remains in the SGs. Item 3 above is satisfied by ashowing that the maximum pressurizer pressure remains below the PSV opening setpoint.

In addition to the three requirements listed above, an additional criterion is imposed on the LTC analysis for the AOOs, including LOAC and LONF events. This criterion specifies that maximum pressurizer water volume must remain less than 1519 ft^3, thus ensuring that a water solid state is not reached in the pressurizer and the LOAC and LONF events do not propagate into a more severe event.

The LTC analysis of the LONF and FLB events at EPU was performed for cases with and without a LOOP. The LONF analysis with a LOOP was performed to bound the LOAC event, which is initiated from a LOOP that results in an immediate loss of normal feedwtaer. Consistent with the analyses performed in FSAR Section 10.4.9A, the LTC analysis is a best-estimate analysis with some bias in the conservative direction. In the analysis nominal initial parameters were considered.

Tables SRXB-61-1 and SRXB-61-3 illustrated the assumptions and values of the key parameters used in the LTC analysis for the LONF and FLB event, respectively. For both events, nominal values of the initial RCS temperature and pressure, and initial pressurizer and SG water level were used. The non-nominal values were also used for the following plant parameters: (1) the power level based on the EPU power plus uncertainty, (2) a degraded AFW flow of 275 gpm from each of the two motor-driven AFW pumps with a single failure that resulted in a loss of the turbine driven AFW pump, (3) the AFW actuation setpoint based on the nominal setpoint minus uncertainty with a signal delay time of 330 seconds, and (4) the low SG level reactor trip based on a nominal setpoint minus uncertainty. The use of non-nominal values would either increase the energy stored in the RCS or decrease the AFW capability for removal of the decay heat, resulting in a longer time or requiring a larger amount of AFW to cool down the plant, and were conservative. In addition, non-safety related systems were assumed operable. These systems included: the pressurizer PORVs, pressurizer sprays and heaters, and charging/letdown for the cases without LOOP; and pressurizer PORVs and sprays for the cases with LOOP.

Consistent with the current design basis, LONF LTC analysis was performed for period of one hour without crediting operator actions. The results for cases with and without LOOP showed that: (1) more than 10 percent of the initial SG mass existed in either SG at the end of the transient and the RCS temperature continued to decrease after it reached a peak temperature of 595 °F, ensuring that sufficient SG heat transfer capability was available for plant cooldown, (2) the pressurizer water volume remained below 1519 ft^3, ensuring that the pressurizer did not reach a water solid condition; (3) the prressurizer pressure remained below the PSVs and the PSVs did not open; and (4) subcooling margin was maintained throughout the transient.

The FLB LTC analysis was performed in accordance with FSAR Section 1 0.4.9A for four cases: (1) a high initial RCS average temperature without LOOP; (2) a high initial RCS average temperature with LOOP; (3) a low initial RCS average temperature without LOOP; and (4) a low initial RCs average temperature with LOOP. Consistent with the current design basis, the analysis was performed for 30 minutes without crediting operator actions. The results in Table SRXB-61-4 showed that for all cases: (1) there was greater than 7800 Ibm in either SG at the end of the transient; (2) the pressurizer water volume remained below 1519 ft^3, ensuring that the pressurizer did not reach a water solid condition; and (3) subcooling margin was maintained throughout the entire transient. Although the pressurizer emptied for the case initiating from the high RCS average temperature without LOOP, the analysis showed that there was no voiding in the RV upper head or RCS hot legs, and subcoolng margin was maintained during the transient. Also, the analysis identified that the case starting from a high RCS average temperature without LOOP was the limiting case with respect to minimum unaffected SG mass; and the case with a low initial RCS average temperature in combination with LOOP was the limiting case in terms of maximum pressurizer liquid volume. Both limiting cases maintained more than 45 °F of subcooling.

Since the LTC analysis was performed based on the methods, initial conditions, and assumptions consistent with that for the current design basis, and results showed that the LTC could be achieved without pressurizer overfill that could prevent the PORVs or PSVs from closing after they were open. The results of the analysis adequately supported that the LOAC and LONF event would not generate a more severe conditions (such as un-isolable small break loss-of-coolant), thus, meeting the third AOO acceptance criterion (the other two acceptance criteria were no violation to SAFDLs and RCPB pressure limits). The result applied to the FLB, an accident, in meeting a more restrictive third acceptance criterion for AOOs was also acceptable.

Conclusion

The NRC staff has reviewed the licensee's discussion of the LONF event and concludes that the consequences of the LONF event are bounded by the analyses of the LOF and LOCV events, which are found acceptable in meeting the SAFDLs and the RCPB pressure limits. Based on this, the NRC staff concludes that the plant will meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff determines that the proposed EPU is acceptable with respect to the LOAC event.

2.8.5.2.4 FW System Pipe Breaks Inside and Outside Containment

Regulatory Evaluation

A major FW line break (FWLB), an ANS Condition IV event, is defined as a break in a FW line large enough to prevent the addition of sufficient FW 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 FW flow to the affected RCS loop). The cooldown situation resembles an MSLB, and heatup scenario resembles an LONF. In either case, reactor protection or 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 nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and

(4) GDC 35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling.

Specific review criteria are contained in SRP Section 15.2.8 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Section 2.8.5.2.4 of licensing report discusses the FLB analysis for EPU application. The analysis was performed with Westinghouse RETRAN computer code. RETRAN was previously reviewed and approved by the NRC for the FLB analysis documented in Section 15.2.8 of the St. Lucie 2 FSAR, and it remained aceptable.

The initial conditions and assumptions used in the analysis are discussed as follows.

● The initial reactor power level is assumed to be at EPU power plus uncertainty; the initial RCS flow rate is assumed at a value consistent with the thermal design flow rate (for addressing over-pressurization concerns) or minimum measured flow rate (for addressing DNBR concerns);

and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant TS minus the pressure measurement uncertainty.

- For maximum RCS pressure, the RCS temperature is assumed to be at low-T_{avg} conditions minus uncertainty. For maximum MSSS pressure, the RCS temperature is assumed to be at high-T_{avg} conditions plus uncertainty.

- For maximum RCS pressure and DNB, the initial SGTP level is assumed to be at the maximum plugging level. For maximum MSSS pressure, the initial SGTP is assumed to be at the minimum plugging level.

- The initial SG water level is assumed to be at the minimum water level, consistent with the low-level alarm setpoint minus the SG level measurement uncertainty.

- The high pressurizer pressure (HPP) and low SG pressure reactor trip setpoints for adverse conditions are assumed. The low SG level reactor trip is not credited.

- The FLB is assumed to occur at the inlet nozzle location on the SG.

- An fL/D of 0 (zero) is assumed for the break and the blowdown quality is calculated by the RETRAN code.

- A break size spectrum is analyzed to determine the limiting size with respect to DNBR, RCS and MSSS over-pressurization.

- Minimum reactivity feedback is assumed to maximize the energy input to the primary coolant.

- No credit is taken for the effect of the pressurizer spray in reducing or limiting primary coolant pressure with respect to RCS overpressurization; PSVs are available and are modeled with lift setpoits with a +3 percent tolerance; the PORV is not considered since it would actuate after reactor trip on HPP and limit the pressure increase.

- Credit is taken for the effect of the pressurizer spray in reducing primary coolant pressure and delaying reactor trip on HPP for the MSSS overpressurization and DNB cases; PSVs are available and are modeled assuming a +3 percent setpoint tolerance; and the PORV is assumed to actuate once reaching the HPP reactor trip setpoint. Note that per the TS 3.4.4, one PORV block valve is required to be closed during Modes 1, 2, and 3, thus only one PORV is allowed to be operable.

Since the above selected initial conditions and assumptions are consistent with that of the existing FLB methodology to maximize the peak RCS and secondary pressure experienced and minimize the DNBR during the FLB event, they remain acceptable.

The FLB analysis did not include a LOOP after turbine trip on the reactor trip. The LOOP does not adversely impact the RCS overpressurization results, since the peak RCS pressure occurs soon after reactor trip on HPP signal. For the MSSS pressure case, losing RCPs due to a LOOP retards heat transfer to the intact SG, leading to a lower peak secondary side pressure and therefore is not modeled. This assumption is consistent with that of the AOR for the FLB event and remains acceptable. A FFBT at reactor/turbine trip, the most limiting single failure in the AOR, was included in the analysis addressing RCS overpressurization. This assumption is also acceptable since it is consistent with that of the AOR and will increase the peak RCS primary pressure.

For the FLB analysis, the licensee considered following cases:

- RCS Overpressurization Cases - for small breaks from 0.10 ft^2 to 0.20 ft^2 and for large breaks from 0.21 ft^2 to 0.375 ft^2

- MSSS Overpressurization Cases - for breaks from 0.05 ft^2 to 0.375 ft^2

- DNBR Cases – for breaks from 0.15 ft^2 to 0.375 ft^2

In the response to SRXB-62 (Reference 11), the licensee indicated that the analysis covered up to the 0.375 ft^2 break was based on the AOR results showing that as the break size increases larger than 0.300 ft^2, the FLB becomes more benign. Therefore, the license determined that analyzing break larger than 0.375 ft^2 would not produce more limiting results. The EPU analysis also showed that break sizes close to 0.375 ft^2 were less limiting than the limiting case (0.21 ft^2) included Section 2.8.5.2.4 of the licensing report (Reference 2). The range of break sizes classified into small and large break are determined based on probability of occurrence. The categorization of break sizes to the large and small breaks addressing RCS ovepressurization was used for the analysis to meet the separate RCS pressure limits, 120 percent and 110 percent of the design pressure for the large and small FLB, respectively.

In addition, the classification and range of break sizes and the associated acceptance criteria are consistent with that of the AOR included in the FSAR 15.2.8, and therefore, they remain acceptable.

Using the acceptable assumptions and initial conditions discussed above, the break spectrum study identified the limiting breaks with respect to peak RCS primary pressure, secondary pressure, and the lowest minimum DNBR. The results of the sensitivity study are provided in Table 2.8.5.2.4-1 of the licensing report (Reference 2). Table 2.8.5.2.4-1 indicates that the limiting break sizes with respect to peak RCS primary pressure are 0.21 ft^2 for the large breaks with and without FFBT, 0.20 ft^2 for the small breaks with FFBT and 0.10 ft^2 for the small breaks without FFBT, and that all break sizes with and without FFBT satisfy the 110 percent of design pressure criterion. Table 2.8.5.2.4-2 and Table 2.8.5.2.4-3 provide the sequence of events for the limiting large and small breaks, respectively.

For the analysis addressing peak RCS secondary pressure, the results in Table 2.8.5.2.4-1 of the licensing report show that the limiting break is 0.050 ft^2 with the peak pressure of less than 1095 psia, which is within the limit of 1100 psia (the 110 percent of the design pressure acceptance criterion). Table 2.8.5.2.4-4 provides the sequence of events for the limiting break regarding the peak secondary pressure.

For the analysis addressing the minimum DNBR, the results in Table 2.8.5.2.4-1 show that the limiting break is 0.20 ft^2 with the lowest minimum DNBR of 2.21, which satisfies the safety DNBR limit of 1.42, resulting in no fuel rod failures due to DNB. A comparison with the current DNBR analysis for FLB shows that the value of the lowest minimum DNBR for EPU conditions is greater than that of the current analysis. This higher minimum DNBR, representing a greater margin to DNB, is caused by a larger SG heat transfer area (10 percent versus 30 percent

SGTP) and reduced fuel rated peaking factor (F_r). Table 2.8.5.2.4-5 provides the sequence of events for the limiting break regarding the lowest minimum DNBR.

Since (1) the FLB analysis was performed with approved models and adequate initial conditions and assumptions, (2) the results demonstrated that all cases meet the applicable peak pressure limits, and (3) the DNBR analysis showed that the value of the lowest minimum DNBR for EPU conditions was greater than that of the current analysis, representing a greater margin to DNB, the NRC staff concluded that the FLB analysis was acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the FW system pipe breaks 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 non-brittle manner, the probability of propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 27, 28, 31 and 35 following implementation of the proposed EPU. Therefore, the NRC staff determines that the proposed EPU is acceptable with respect to the FW system pipe breaks.

2.8.5.2.5 Asymmetric SG Transient

Regulatory Evaluation

The asymmetric SG transient (ASGT) is defined as a complete loss of steam load to one SG from a full power condition. The event results in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transient. Section 2.8.5.2.5 of the licensing report discusses the results of the ASGT analysis.

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.

Technical Evaluation

The asymmetric SG transients (ASGTs) which affect a single SG are (1) loss of load to one SG (MSIV closure), (2) excess load to one SG, (3) loss of FW to one SG and and (4) excess FW to one SG. In support of the operation with EPU conditions, the licensee analyzed the loss of load to one SG from a full-power condition, which is the limiting ASGT identified in FSAR Section 15.2.9. The license postulated the ASGT for St. Lucie 2 as an AOO and analyzed it to show that the DNBR limit is met. With respect to the RCS overpressure, the ASGT is bounded by the loss of condenser vacuum event discussed in licensing report Section 2.8.5.2.1, and thus, overpressure analysis is not performed for the ASGT. This approach is acceptable since it is consistent with that of the ASGT analysis in FSAR Section 15.2.9.

The licensee modeled the ASGT as an inadvertent closure of the MSIV to one SG, resulting in a loss of steam flow the affected SG. A concurrent termination of FW flow to the affected SG was assumed in the analysis to conservatively bound any potential response of the FW system. During the transient, its P-T increased to the opening pressure of the MSSVs. As a result of the steam relieved through the MSSVs, the pressure in the affected SG decreased and stabilized at the MSSV setpoint pressure. The unaffected SG continued to supply steam to the turbine. The steam flow from the unaffected SG resulted in an overcooling of the cold legs associated with the unaffected loop. The increase in the core inlet temperature from the affected loops in combination with the decrease in core inlet temperature from the unaffected loops resulted in a large core temperature asymmetry. The asymmetric core temperature conditions would result in an increase in core power and RCS temperature, causing a challenge to the design DNBR safety limit. The high SG DP reactor trip served as the primary means of mitigating this event.

The analysis was performed with Westinghouse RETRAN computer code. The RETRAN method was previously reviewed and approved by the NRC for the ASGT analysis documented in St. Lucie 2 FSAR Section 15.2.9, and it remained acceptable for the ASGT analysis at EPU conditions.

The initial conditions and assumptions used in the analysis are discussed as follows.

- The initial reactor power and RCS temperature are assumed to be at values consistent with 100 percent of rated thermal power; the initial RCS flow rate is assumed at a value consistent with the minimum measured flow rate and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant TSs. Uncertainties in initial conditions are statistically included in the calculation of the DNBR limit as described in an NRC-approved report, WCAP-11397-A, “Revised Thermal Design Procedures”.

- The model assumes end-of-life reactivity feedback coefficients that maximize the increase in nuclear power prior to reactor trip. These reactivity coefficients are weighted to the RCS loop associated with the unaffected SG to maximize the power increase. The effects associated with the asymmetric vessel inlet distribution caused by the transient are used to calculate conservative radial and axial peaking factors.

- Full credit is taken for the effect of the pressurizer spray in limiting any primary coolant pressure increase above the initial pressure thereby, decreasing RCS pressure which results in a more limiting DNB value.

- Trip setpoint uncertainties and delay times discussed in licensing report Section 2.8.5.0 are included.

Since the above selected initial conditions and assumptions are consistent with that of the existing ASGT methodology to minimize the DNBR experienced during the ASGT, they remain acceptable.

The licensee analyzed two cases: one assuming 0 percent of the SG U-tubes to be plugged and one assuming 10 percent of the SG U-tubes to be plugged. These cases would cover any asymmetry within these limits and were consistent with EPU conditions.

The results provided in Table 2.8.5.2.5-4 showed that the calculated minimum DNBR for both cases was 2.229, which was significantly greater than the SAL DNBR of 1.42. Licensing report Tables 2.8.5.2.5-1 and 2.8.5.2.5-2 provided the sequence of events for the ASG with SGTP levels of 0 percent and 10 percent, respectively.

Since the analysis used acceptable methods and acceptable initial conditions and assumptions, and showed that the minimum DNBR remained significantly above the SAL DNBRs, satisfying the acceptance criterion of the DNBR limit in the SRP Section 15 for AOOs, the staff concluded that the ASGT analysis was acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the ASGT described above and concluded 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 has further concluded 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 ASGT. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 10, 15, 20, and 26 following implementation of the proposed EPU. Therefore, the NRC staff determines that the proposed EPU is acceptable with respect to the ASGT.

2.8.5.3 Decrease in RCS Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

Regulatory Evaluation

A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer, which would cause an increase in fuel temperature. Fuel damage could result if the SAFDLs are exceeded during the transient. The RPS will automatically trip the reactor, and this will mitigate the transient (i.e., prevent violation of the SAFDLs).

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 Sections 15.3.1 and 15.3.2, and additional guidance is provided in Matrix 8 of RS-001.

<u>Technical Evaluation</u>

A loss of forced reactor coolant flow event may result from a mechanical failure or electrical failure in one or more RCPs or simultaneous loss of electrical supply to the RCPs. 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, potentially violating safety limit DNBR. Reactor protection and safety systems are actuated to mitigate the transient. The acceptance criteria applicable to this event are that (1) DNBR safety limit is not exceeded, (2) maximum pressure in the RCS and MSSS 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.

The licensee analyzed the complete loss of flow (LOF) event using the following two NRC-approved computer codes: RETRAN calculated the nuclear power, the RCS temperature and pressure, and the core flow during the transient; and VIPRE calculated the heat flux and DNBRs based on the nuclear power and RCS temperature, pressure, and flow from RETRAN. The DNBR calculations were based on the NRC-approved RTDP described in WCAP-11397-P-A. In the DNBR calculations, the initial reactor power, RCS pressure, temperature and flow were assumed to be at their nominal values, and uncertainties in initial conditions were included in the DNBR limit as described in the RTDP. The licensee also assumed (Tables SRXB-49-1 through 49-3 of Reference 11) the minimum value of 0 Δk/gm/cc for the moderator density coefficient, a most negative curve for the Doppler-only power coefficient, and the most positive moderator temperature coefficient of 0 pcm/$^\circ$F at full-power conditions. The analysis assumed a maximum SGTP level of 10 percent (page 2.8.5.0-19 of the licensing report (Reference 2)), resulting in a minimum initial RCS flow. The assumptions for the reactivity feedback and SGTP level maximized the core power and hot spot heat flux, and minimized the DNBR during the transient and, therefore, they were conservative and acceptable. The reactor trip was based on the core flow reaching low flow reactor trip setpoint using a value less than the TS trip setpoint (per licensing report Table 2.8.5.0-4). The use of a lower trip setpoint was conservative and acceptable, since it delayed the reactor trip and resulted in more energy generated in the RCS prior to reactor trip, leading to more challenge to the safety limit DNBR.

The licensee also considered two partial LOF cases: a loss of power to a single RCP case and a loss of power to two RCPs case. However, since the most limiting point in the transient is the point where the poser to flow ratio is the largest, the complete loss of flow event always has a larger power to flow ratio, due to the lower flow. As a result the complete loss of flow will be the more limiting and bound the partial loss of reactor coolant flow cases. The licensee did not analyze the 3-out-of 4 RCP trip event because there was no credible failure that would result in this transient. During normal operation, power is provided to the RCPs through two electrical buses such that bus supplies two diametrically opposed RCPs. Any failure which would result in loss of power to three pumps also would result in loss of power to the fourth pump. The results of the analysis for the limiting case, the complete LOF, showed that the minimum was 1.378.

The current DNBR SAL was reduced to a lower value for the locked rotor analysis at EPU conditions. The reduction was performed through the removal of a portion of the discretionary plant specific margin that was initially added to 95/95 RTDP design limit of 1.29. The reduced DNBR SAL retains sufficient margin to compensate for the required rod bow DNBR penalty and remains conservative with respect to the DNBR design limit of 1.29 listed in licensing report Table 2.8.3-5 (Reference 2), "RTDP DNBR Margin Summary."

The NRC staff reviewed the licensee's DNBR analyses of the LOF events and found that the analyses were analyzed using the NRC-approved methods and acceptable assumptions, and that the results showed that the safety limit DNBR was met. Therefore, the NRC staff determined that the DNBR analysis was acceptable for the proposed EPU application. Licensing report Table 2.8.5.3.1-1 provided sequence of event of the limiting loss of flow case, a complete loss of reactor coolant flow.

With respect to RCS and MSSS over-pressurization, the LOF events were bounded by the LOCV event. For the LOF events, turbine trip would occur simultaneously with reactor trip, while for the LOCV event, the initial conditions were a complete loss of FW and a loss of turbine load. The LOCV event resulted in the termination of main steam flow prior to reactor trip in addition to the total loss of normal FW flow. The termination of the steam and FW flow at the initiation of the LOCV event aggravated RCS pressurization of the RCS pressure compared to the LOF event. The net result for the LOCV event was a total loss of the secondary heat sink at the initiation of the event, which resulted in the greatest challenge to RCS and MSSS over-pressurization. Therefore, the licensee did not perform the overpressure analysis for the LOF at EPU conditions and relied on the results of the overpressure analysis of the LOCV event as the bounding analysis. The licensee's approach was acceptable, since it was consistent with that of the AOR documented in FSAR Section 15.3.1 for the LOF analysis. Therefore, the NRC staff concluded that the consequences of the LOF event were acceptable.

Conclusion

The NRC staff has reviewed the licensee's analysis of the complete LOCF event and concludes that the licensee's analysis has adequately accounted for operation of the plant at the proposed EPU power level, and was performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the RPS will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the staff concludes that the plant will continue to meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the LOCF event.

2.8.5.3.2 RCP Rotor Seizure and RCP Shaft Break

Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of a RCP. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer, which could result in fuel damage. Reactor protection and safety systems are actuated to mitigate the transient.

The NRC staff's review covered:

(1) The postulated initial and long-term core and reactor conditions,

(2) The methods of thermal and hydraulic analyses,

(3) The sequence of events,

(4) The assumed reactions of reactor system components,

(5) The functional and operational characteristics of the RPS, and

(6) 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 nonbrittle manner and the probability of a rapidly propagating fracture is minimized.

Specific review criteria are contained in SRP Sections 15.3.3 and 15.3.4 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Licensing report Section 2.8.5.3.2 describes the analysis of the RCP shaft break/ RCP rotor seizure (locked rotor) events, addresses the breaking of an RCP shaft or the instantaneous seizure of an RCP rotor. The consequences of a postulated locked rotor are similar to the RCP shaft break accident. During the locked rotor or RCP shaft break event, flow through the affected loop is rapidly reduced, leading to a reactor trip on a low-flow signal. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the locked rotor event because the fixed shaft causes greater resistance than a free spinning impeller earlier in the transient, when flow through the affected loop is in the positive direction. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. Because peak pressure, cladding temperature and DNB occur very early in the transient, the reduction in core flow during the period of forward flow in the affected loop dominates the severity of the results. Therefore, the licensee analyzed the limiting case, the locked rotor event.

For the analysis of the locked rotor event, the licensee used NRC-approved codes and methods: RETRAN for calculation of the loop and core flow rate during the event, the nuclear power transient, and the RCS P-T transients, and VIPRE for the DNBR calculation. The DNBR calculations were based on the RTDP described in WCAP-11397-P-A. In the DNBR calculations, the initial reactor power, RCS pressure, temperature and flow were assumed to be at their nominal values, and uncertainties in initial conditions were included in the DNBR limit as described in the RTDP. In the RCS P-T calculations, the licensee used the standard thermal design procedure (STDP) assuming maximum values for the initial power level, RCS P-T with inclusion of the measurement uncertainties to maximize the calculated peak RCS pressure. The licensee also assumed a large absolute value of the Doppler-power coefficient with the most positive moderator temperature coefficient for full power operation. The analysis assumed a maximum, uniform SGTP level of 10 percent, resulting in a minimum initial RCS flow. These assumptions would maximize the core power and minimize the DNBR values, and were, therefore, conservative and acceptable. Following the locked rotor, reactor trip was initiated on a low RCS flow signal. The analysis modeled failure of one fast bus transfer (FFBT), coincident with reactor the reactor trip. An FFBT would result in the immediate loss of two RCPs. The assumption of an FFBT in the locked rotor analysis was consistent with that assumed in the analysis of record (AOR) for St. Lucie 2.

The current DNBR SAL was reduced to a lower value for the locked rotor analysis at EPU conditions. The reduction was performed through the removal of a portion of the discretionary plant specific margin that was initially added to 95/95 RTDP design limit of 1.29. The licensee showed (on pages 2 and 3 of Attachment 2 to L-2012-150 (Reference 50)) that the reduced DNBR SAL retained sufficient margin to compensate for the required rod bow DBNR penalty and remained conservative with respect to the DNBR design limit of 1.29 listed in licensing report Table 2.8.3-5 (Reference 2), "RTDP DNBR Margin Summary."

The results of the locked rotor analysis showed in Table 2.8.5.3.2-2 of the licensing report (Reference 2) that the minimum DNBR was no less than the reduced SAL DNBR, assuring no fuel rod failures due to DNB. However, a value of less than 1 percent for rods-in-DNB was conservatively reported for the EPU analysis. The value of less than 1 percent was significantly less than the value (19.7 percent) used in the dose consequences analysis that was used to meet the dose limits. Also the results showed that the peak RCS pressure was 2657.82 psia, which was below 110 percent of the design pressure.

With respect to MSSS over-pressurization, the results of the locked rotor event are less limiting than that of the LOCV event discussed in Section 2.8.5.2.1 of this report. For the locked rotor event, turbine trip occurs simultaneously with reactor trip, while for the LOCV event, the initial conditions are a complete loss of FW and a loss of turbine load. The LOCV event results in the termination of main steam flow prior to reactor trip in addition to the total loss of normal FW flow. The net result for the LOCV event is a total loss of the secondary heat sink at the initiation of the event, which results in the greatest challenge to MSSS over-pressurization.

The NRC staff reviewed the licensee's analyses of the locked rotor event and accepted the licensee's application of the NRC-approved analytical models. Since the locked rotor analysis showed that the fuel rods-in-DBN was bounded by that used in the dose analysis, and the peak RCS primary and secondary pressures were within the safety pressure limits, the staff determined that the proposed uprate was acceptable with respect to the postulated RCP locked rotor accident.

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 nonbrittle 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, 28, and 31 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the sudden decrease in core coolant flow events.

2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition

Regulatory Evaluation

An uncontrolled CEA withdrawal from subcritical or low power startup conditions could be caused by malfunction of the reactor control or CEA control systems, or by an operator error. This withdrawal will add positive reactivity to the reactor core, and cause a power excursion. This event is classified as an AOO, or an ANS Condition II event.

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 upon:

(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.

Technical Evaluation

A CEA withdrawal from a subcritical condition or low-power start-up condition will add positive reactivity to the reactor core, resulting in a power excursion. Such an event causes an increase in fuel and coolant temperature as a result of the core-turbine power mismatch. Reactor trips, including the VHPT, and rate of change of power trip, provide plant protection.

The analysis assumed the reactor to be at HZP nominal temperature. When compared to shutdown conditions, the higher HZP initial RCS temperature would yield a larger fuel-to-water heat transfer coefficient, a larger specific heat of the water and less negative DPC. The less negative DPC reduced the Doppler feedback effect, thereby increasing the neuron flux peak. The high neutron flux peak combined with a larger heat transfer coefficient would yield a larger peak heat flux. Also, the assumption of using the HZP nominal temperature as an initial RCS temperature was consistent with that assumed in the AOR, which calculated the minimum DNBR.

For the analysis of this event, the licensee used the previously NRC-approved computer codes: TWINKLE (WCAP-7979-P-A, ADAMS Accession No. ML080650324) for the average nuclear power transient including Doppler and moderator reactivity; FACTRAN (WCAP-7908-A, ADAMS Accession No. ML080630436) for the hot rod heat transfer calculation; and VIPRE (WCAP-14565-P-A, ADAMS Accession No. ML993160153) for the DNBR calculation. The DNBR calculation was based on the previously NRC-approved STDP, which is the traditional design method with parameter uncertainties applied deterministically in the limiting direction. The RTDP was not used for the DBNR calculation because the conditions for the transient fell outside the range of applicability of the RTDP. Consistent with the STDP, the RCS flow rate was based on the thermal design flow and the RCS pressure was the nominal pressure minus the uncertainty. Since the event was analyzed from HZP, the steady-state STDP uncertainties on core power and RCS average temperature were not used in defining the initial conditions. The use of the STDP was consistent with that of the AOR in FSAR Section 15.4.1.2 and thus, remained acceptable.

The analysis assumed a conservatively low value for the Doppler-power defect and the most positive value for the moderator temperature coefficient (per Table SRXB-49-2 of FPL letter L-2011-532 (Reference 11)) to maximize the peak heat flux. Reactor trip was assumed to occur on the VHPT signal with the setpoint of 35 percent of full power, which included a 20-percent uncertainty. The analysis assumed that the maximum positive reactivity insertion rate was 53 pcm/sec. This assumed reactivity rate exceeded that for the simultaneous withdrawal of the two sequential CEA banks having the greatest combined worth at the maximum speed. The DNBR calculation assumed the most limiting axial and radial power shapes associated with the two highest-worth banks in their highest-worth position. The initial power level was assumed to be below the power level expected for any shutdown conditions. The combination of the highest reactivity addition rate and lowest initial power produced the highest peak heat flux, resulting in a lowest calculated minimum DNBR, and was conservative.

The results of the analyses showed in licensing report Table 2.8.5.4.1-2 of the licensing report (Reference 2) that the peak fuel centerline temperature for this transient was 3432°F, which is significantly below the minimum temperature expected for fuel melt, 4717°F, which was based on the NRC-approved method documented in CENPD-275-P-SUPP 1-P-A (per the licensee's response to RAI SRXB-64 of L-2011-532 (Reference 11)).

The minimum DNBR for this transient was 1.28, which is greater than the DNBR SAL of 1.26 listed on licensing report Table 2.8.5.4.1-3. The DNBR SAL of 1.26 was reduced from the current DNBR SAL of 1.29. The reduction was performed through the removal of a portion of the discretionary plant specific margin that was initially added to STDP DNBR correlation limit of 1.13. The licensee showed (on pages 2 and 3 of Attachment 2 to L-2012-150 (Reference 50)) that the reduced DNBR SAL retained sufficient margin to compensate for the required rod bow DBNR penalty and remained conservative with respect to the DNBR correlation limit of 1.13 listed in licensing report Table 2.8.3-5 (Reference 2), "RTDP DNBR Margin Summary."

The calculated peak fuel centerline temperature and minimum DNB demonstrated that no fuel melting and DNB would occur during the transient.

Based on the above discussion, the NRC staff concluded that the licensee's analysis was performed using acceptable analytical models with conservative assumptions regarding initial conditions, nuclear parameters, and mitigating RPS trip signals. The NRC staff also found that the analyses met the requirements of (1) GDC 10, in that the DNBR SAL was not exceeded, (2) GDC 20, in that the reactivity control system could be initiated automatically so that DNBR SAL was not exceeded, and (3) GDC 25, in that a single malfunction in the reactivity control system would not cause the DNBR SAL to be exceeded.

Therefore, the NRC staff determined that the proposed EPU was acceptable with respect to the uncontrolled CEA withdrawal from a subcritical condition event.

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition and concludes that the licensee's analyses have adequately accounted for the changes in core design necessary for operation of the plant at its 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 these considerations, the NRC staff concludes that the plant will continue to meet the requirements of GDC 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff determines that the proposed EPU is 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

Regulatory Evaluation

An uncontrolled CEA withdrawal at power may be caused by a malfunction of the reactor control or CEA control systems, or by operator error. This withdrawal will add positive reactivity to the reactor core, and cause a power excursion. This event is classified as an AOO, or an ANS Condition II event.

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 upon:

(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.

Technical Evaluation

Unlike the uncontrolled CEA withdrawal from subcritical or low power startup condition, the uncontrolled CEAWAP 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. Reactor trips, including trip signals from the VHP, HPP, TM/LP, and high local power density, provide plant protection.

The licensee performed the analysis of the CEAWAP with the previously NRC-approved methods: the RETRAN code (WCAP-14882-P-A, ADAMS Accession No. ML093421329) calculated the nuclear power transient, and the RCS P-T transients, and ANC code (WCAP-10965, ADAMS Accession No. ML080630392) calculated the peak linear heat rate based on the nuclear power, RCS temperature, and core flow from RETRAN. The licensee analyzed both DNBR and over-pressurization cases.

For DNBR calculations, the licensee analyzed CEAWAP cases with both minimum and maximum reactivity feedback coefficients, and performed a sensitivity study of the effects of initial power levels (20, 50, 65 and 100 percent of full power). For minimum reactivity feedback cases, a moderator temperature coefficient (MTC) of zero was assumed at full power. For power less than or equal to 70 percent power, a positive MTC, corresponding to the beginning of core life, was assumed. A conservatively small (in absolute magnitude) Doppler power coefficient was used. For maximum reactivity feedback cases, the analysis used a large negative MTC, a large positive moderator density coefficient and a large negative Doppler power coefficient. The initial reactor power, RCS pressure, temperature and flow were assumed to be at their nominal values, and uncertainties in initial conditions were included in the DNBR limit as described in the RTDP (WCAP-11397-P-A, ADAMS Accession No. ML080650330). The minimum RCS flow was used to minimize the calculated DNBRs.

For over-pressurization calculations, the licensee used the STDP methodology to maximize the calculated peak RCS pressure. Uncertainties were applied to the nominal values for the initial reactor power, RCS temperature, and pressure. Specifically, the appropriate uncertainties were added to the reactor power and RCS temperature. A spectrum of cases considered two initial pressure conditions (2180 psia and 2395 psia) corresponding to the application of positive and negative pressure uncertainties. Thermal design flow was assumed. The analysis assumed the minimum reactivity feedback conditions. Also, the licensee performed a sensitivity study of the effects of initial power levels (25, 50, 75, 85, 90, 95 and 100 percent of full power) on the peak RCS pressure with an initial pressurizer pressure of 2395 psia.

As indicated in Table 2.8.5.0-4 and page 2.8.5.4.2-4 of the licensing report (Reference 2), for all cases, the VHP trip was assumed to occur at TS trip setpoint of 107 percent of RTP plus uncertainties (resulting in an analytical value of 112 percent RTP). The HPP trip was assumed to occur when the pressurizer pressure reached 2415 psia, which was based on the TS values plus pressure measurement uncertainty. The TM/LP trip was modeled without taking credit for any reduction in the calculated trip setpoint pressure associated with any skewed axial shape index. The Δ-power (a power increase above the initial power level) feature of the VHP trip was assumed to trip the reactor when the Δ-power reached the setpoint of 11.7 percent RTP and 13.6 percent RTP for the cases initiated from power levels less than 100 percent RTP and greater than 35 percent RTP, and power levels less than and equal to 35 percent RTP, respectively. In addition, the analysis considered a range of reactivity insertion rates (from 1 pcm/sec to a value greater than 53 pcm/sec that is the maximum reactivity insertion rate resulting from the simultaneous withdrawal of two control rod banks). The CEA trip insertion characteristics were based on the assumption that the highest worth assembly was stuck in its fully withdrawn position.

The analyses for the limiting cases of the CEARAP event showed in Table 2.8.5.4.2-2 of the licensing report (Reference 2) the following results:

Limiting Results for CEAWAP

	Limiting Analysis Value	Analysis limit	Case
DNBR	1.74	1.42	100% power, maximum feedback, 53 pcm/sec
Peak linear heat rate (kW/ft)	14.9	22.0	100% power, maximum feedback, 53 pcm/sec
RCS pressure (psia)	< 2487	2750	100% power, minimum feedback, 53 pcm/sec, 2395 psia initial pressure
Pressurizer Overfill (ft^3)	1483.4	1519	100% power, maximum feedback, 1 pcm/sec

The above results of the analyses showed that with the combination of the VHP, HPP and TM/LP trips, the DNBRs would not fall below the safety limit DNBR and the peak heat generation rate was less than the limit value for fuel melting for the limiting cases. Therefore, fuel integrity and adequate fuel cooling would be maintained. The calculated peak RCS pressure was less than 110 percent of the design pressure, assuring integrity of the RCPB. In addition, the licensee confirmed that the peak pressurizer water volume would not be sufficient to fill the pressurizer, assuring that this event would not develop into a more serious event, by causing a PORV to stick open, after it has relieved water.

In conclusion, the licensee demonstrated acceptable performance for this AOO using acceptable analytic methods. On this basis, the NRC staff determined that the licensee's analysis and analytic results for the CEAWAP event were acceptable for the proposed EPU.

Conclusion

The NRC staff has reviewed the licensee's analyses of the CEAWAP 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 finds 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, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff determines that the proposed EPU is acceptable with respect to the CEAWAP event.

2.8.5.4.3 Control Rod Misoperation

Regulatory Evaluation

A CEA misoperation event is initiated by a single electrical or mechanical failure in a CEA drive mechanism which causes any number and combination of rods from a CEA subgroup to drop to the bottom of the core. 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) that can mitigate the effects or prevent the occurrence of various misoperations; (2) the sequence of events; (3) the analytical model used for analyses; (4) important inputs to the calculations; and (5) the results of the analyses. The NRC's acceptance criteria are based on:

(1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs;

(2) GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to initiate automatically operation of systems and components important to safety under accident conditions; and

(3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems.

Specific review criteria are contained in SRP Section 15.4.3 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The CEA misoperation event includes full-length CEA drop and full-length CEA subgroup drop. In this event, the core power initially decreases due to the insertion of negative reactivity resulting from the dropped control rod. Moderator and Doppler temperature feedback causes power to return to its initial level at a reduced RCS temperature and pressure condition. The event results in a localized increase in the radial peaking factor, which causes DNBR to decrease.

For the St. Lucie 2 design, automatic rod withdrawal capabilities have been removed. Also, the automatic withdrawal prohibit remain functional at the St. Lucie 2 plant and activates via rod bottom contacts. As a result, the control rods would not automatically withdraw in response to a power mismatch following a dropped CEA. With a decrease in reactor power, the turbine load is not reduced and remains the same as prior to the dropped CEA. In consistency with the St. Lucie 2 design discussed above, the system transient for the CEA drop event was calculated by assuming a constant turbine load demand and no CEA bank withdrawal. In the analysis, the licensee used the NRC-approved RETRAN to calculate the pressure, temperature, power and RCS flow in the transient, and nuclear models (the NRC-approved ANC computer code as indicated on page 2.8.5.0-18 of the licensing report (Reference 2)) to calculate a hot channel factor consistent with the RCS primary system conditions and reactor power calculated by RETRAN, and VIPRE to determine whether the safety limits of DNB and fuel centerline melting temperature were met. In the calculation, VIPRE iterated on the hot channel factor until the SAL DNBR was obtained. The licensee then compared these hot channel factors against the design hot channel factor, used in reload cycle designs, to verify that the transient met SALs. The licensee analyzed a number of cases for the CEA drop event with assumptions covering (1) a range of moderator temperature coefficients to bound the values from beginning of life to end of life, and (2) a spectrum of dropped CEA worths from 100 pcm to 1000 pcm in 100 pcm intervals to bound both single and subgroup CEA drops.

In the DNBR calculations, the initial reactor power, RCS pressure, temperature and flow were assumed to be at their nominal values, and uncertainties in initial conditions were included in the DNBR limit as described in the NRC-approved RTDP documented in WCAP-11397-P-A, ADAMS Accession No. ML080630437). Minimum measured flow of 195,000 gpm/RCS loop wss modeled as the nominal RCS loop flow rate. An SGTP level of 0 percent was assumed to maximize the cooldown effect of this event.

The results showed that in cases where reactivity feedback did not offset the worth of the dropped CEA, a cooldown conditions existed until a reactor trip was actuated on a TM/LP (floor) or a low SG pressure trip signal, and that in cases where reactivity feedback was sufficient to offset the worth of the dropped CEA, reactor power was reestablished at the original power level at a reduced RCS temperature and pressure condition. In all cases, the minimum DNBR remained greater than the safety limit DNBR. Licensing report Tables 2.8.5.4.3-1 and 2.8.5.4.3-2 provided the sequence of events of a dropped CEA at MTC of 0 pcm/°F and -25 pcm/°F, respectively.

Based on the above discussion, the NRC staff concluded that the licensee's analysis was performed using acceptable analytical models with conservative assumptions regarding initial conditions, nuclear parameters, and mitigating RPS trip signals. The NRC staff also found that the analyses met the requirements of (1) GDC 10, in that the DNBR SAL was not exceeded, (2) GDC 20, in that the reactivity control system could be initiated automatically so that DNBR

SAL was not exceeded, and (3) GDC 25, in that a single malfunction in the reactivity control system would not cause the DNBR SAL to be exceeded. Therefore, the NRC staff concluded that the proposed EPU was acceptable with respect to the analysis of the CEA drop event.

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, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff determines that the proposed EPU is acceptable with respect to control rod misoperation events.

2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature

Regulatory Evaluation

A startup of an inactive loop transient may result in either an increased core flow or the introduction of cooler or deborated water into the core. This event causes an increase in core reactivity due to decreased moderator temperature or moderator boron concentration.

The NRC staff's review covered:

(1) The sequence of events,
(2) The analytical model,
(3) The values of parameters used in the analytical model, and
(4) The results of the transient analyses.

The NRC's acceptance criteria are based on

(1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs;

(2) GDC 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;

(3) GDC 20, insofar as it requires that the protection system be designed to automatically initiate the operation of appropriate systems to ensure that SAFDLs are not exceeded as a result of operational occurrences;

(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; and

(5) 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 15.4.4-5 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The licensee stated that the St. Lucie 2 TS 3.4.1.1 would not allow the reactor to go critical with only one RCP in operation. Therefore, the licensee did not analyze this event. The NRC staff found that the licensee's disposition of this event was acceptable because St. Lucie 2 TS would preclude critical operation with a single RCP in service.

Conclusion

The NRC staff has reviewed the licensee's disposition regarding the inactive loop startup event and concludes that the licensee's disposition appropriately accounts for operation of the plant at the proposed power level. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 10, 15, 20, 26, and 28 following implementation of the proposed EPU.

2.8.5.4.5 CVCS Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant

Regulatory Evaluation

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

The NRC staff's review covered

(1) Conditions at the time of the unplanned dilution,
(2) Causes,
(3) Initiating events,
(4) The sequence of events,
(5) The analytical model used for analyses,
(6) The values of parameters used in the analytical model, and
(7) Results of the analyses.

The NRC's acceptance criteria are based on

(1) GDC 10, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including AOOs;

(2) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and

(3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

Specific review criteria are contained in SRP Section 15.4.6 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The main cause of an inadvertent boron dilution event is failure of the CVCS that adds to the core by feeding unborated water into the RCS via the reactor makeup portion of the CVCS. SRP 15.4.6 requests that at least 15 minutes is available from the time the operator is made aware of an unplanned boron dilution event to the time a total loss of SDM occurs during power operation (Mode 1), startup (Mode 2), hot standby (Mode 3), hot shutdown (Mode 4), and cold shutdown (Mode 5). A warning time of 30 minutes is required during refuel (Mode 6).

In licensing report Section 2.8.5.4.5.2.1 (Reference 2), the licensee stated that the following signals were available to detect the event occurrence: the signals from a thermal margin/low pressure (TM/LP) trip, a VHPT; and a HPP for Mode 1; and a signal from a high power trip or a high rate of change of power trip for Mode 2. In Mode 3, 4, 5, and 6, the boron dilution alarm system (BDAS) used the startup channel nuclear instrumentation signal to detect a boron dilution event. There were two redundant and independent channels in the BDAS to ensure detection and alarming of the event. In the case that the BDAS was inoperable, the requirements for maximum frequency of RCS chemistry sampling in licensing report Table 2.8.5.4.5-6 (Reference 2) ensured that sufficient time would be available to the operators, from the detection of dilution until criticality, to mitigate the consequences of this event. The EPU monitoring frequencies were comparable to those of the current analysis.

The licensee analyzed the boron dilution event to show that the analytical results met the SRP acceptance criteria for all modes of operations. The method used for the analysis consisted of a generic fluid mixing model, which was consistent with the model used in the AOR for St. Lucie 2, and remained acceptable. Analysis of this event involved a calculation of the time required for a constant dilution rate to lose available SDM. The key parameters were the dilution flow rate, the active RCS volume, the initial boron concentration and the critical boron concentration (Reference 54). The licensee analyzed for Mode 3 through 6 various cases assuming that 1, 2, and 3 charging pumps are operating with the maximum capacity of 49, 98, or 147 gpm, respectively. For Mode 1 and 2, the licensee analyzed for each case assuming that three charging pumps were operating with the maximum capacity of 147 gpm. For each case analyzed, the analysis used the cycle specific values of maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions that would be determined and verified every cycle as part of the reload verification process. For Mode 3 through 6, the analysis used a BDAS setpoint that corresponded to a flux multiplication of greater than 2.0 plus uncertainty. The above conditions used in the analysis were consistent with those assumed in the AOR analysis, therefore, were acceptable. Water volumes used in the analysis are discussed as follows.

- Mode 6 (Refueling)

In Mode 6, the water in the RV was maintained at the centerline of the hot leg of the RCS. The primary coolant flow is provided by the SDC system. The analysis assumed a reduced RCS water volume of 3410 ft^3 that is smaller than the volume necessary to fill the RV up to the mid-plane of the hot-leg plus the volume of one SDC train.

- Mode 5 (Cold Shutdown)

In Mode 5, the water level can be drained to the mid-plane of the hot leg for maintenance work that requires the SGs to be drained. The analysis assumed a reduced RCS water volume of 3410 ft^3 corresponding to the active reactor volume without inclusion of the pressurizer volume for the case with water level at the hot leg centerline, and 2655 ft^3 corresponding to the active reactor volume for the case with water level at the bottom of hot leg.

- Mode 4 (Hot Shutdown)

In Mode 4, the RCS flow can be provided by either the SDC or a RCP, depending on the RCS pressure. The analysis assumed a minimum RCS water volume of 3711 ft^3 corresponding to the active reactor volume without inclusion of the pressurizer volume for the case with the plant on SDC with no RCPs running. The analysis was performed for the case with the plant operating with at least one RCP using a minimum RCS water volume of 8332 ft^3 (not including the pressurizer volume, but including the effects of 10 percent SGTP).

- Mode 3 (Hot Standby)

For Mode 3, the analysis was performed using a minimum RCS water volume of 8332 ft^3, which represents the active reactor volume not including the pressurizer volume and including the effects of 10-percent SGTP for the case assuming that at least one RCP is running.

- Mode 2 (Startup)

In Mode 2, the plant is being taken from Mode 3 (hot standby) to Mode 1 power operation. During this Mode the plant is in manual rod control with the operator required to maintain a high level of awareness of the plant status. For a normal approach to criticality, the operator manually initiates a limited dilution and then withdraws the control rods, or withdraws the rods to predetermined critical rod position and then dilutes to criticality. The TSs require that the reactor does not go critical with the control rods below the insertion limits. The licensee indicated that for boron dilution event with slow reactivity additions, the reactivity is bounded by the CEA withdrawal event. For fast reactivity additions, the reactivity excursion is protected by the high rate of change of power reactor trip.

The analysis was performed using a minimum RCS water volume of 8332 ft^3, which represents the active reactor volume not including the pressurizer volume and including the effects of 10-percent SGTP.

- Mode 1 (At-Power)

In Mode 1, if the reactor is in automatic rod control, the power and temperature increase from the boron dilution results in insertion of the control rods and a decrease in available shutdown margin. The rod insertion limit alarms would alert the operator to the dilution. If the reactor is in manual control, the power and temperature rise would cause the reactor to reach the TM/LP trip, VHPT, or HPP trip setpoint, resulting in a reactor trip.

The analysis was performed using a minimum RCS water volume of 8332 ft^3, which represents the active reactor volume not including the pressurizer volume and including the effects of 10-percent SGTP.

Results

The results of the analysis showed that the operator would have at least 15 minutes for Mode 3 through 5 and 30 minutes for Mode 6 from an alarm announcing an unplanned boron dilution to the loss of SDM. For Mode 1 and 2, the operator would have at least 15 minutes from the reactor trip to loss of SDM. The sequences of events for the boron dilution events initiating from Mode 1 through Mode 6 were provided in the response to RAI SRXB-69 (Reference 11). These results demonstrated the compliance with the SRP Section 15.4.6 acceptance criteria with respect to the operator action times to terminate the boron additions. In all cases, the licensee assumed maximum dilution flow rates and made assumptions to minimize the existing RCS inventory. The combination of these assumptions shortened the predicted available time to loss of SDM, such that the analytic results were conservative. Based on these considerations, the NRC staff concluded that the licensee's analysis of the boron dilution events was acceptable.

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 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, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff determines that the proposed EPU is acceptable with respect to the boron dilution event.

2.8.5.4.6 Spectrum of Rod Ejection Accidents

Regulatory Evaluation

A CEA is assumed to be ejected as the result of a complete circumferential break of either the CEDM housing or its nozzle section on the RV head. Abrupt removal, or ejection, of a CEA causes a rapid positive reactivity insertion, and creates an adverse power distribution in the core, which could lead to localized fuel rod damage. Fuel temperatures rapidly increase, prompting fuel pellet thermal expansion. The reactivity excursion is initially mitigated by Doppler feedback and delayed neutron effects followed by reactor trip.

The NRC staff evaluates the consequences of a CEA ejection accident to determine the potential damage caused to the RCPB and to determine whether the fuel damage resulting from such an accident could impair cooling water flow. The NRC staff's review covered initial conditions, rod patterns and worths, scram worth as a function of time, reactivity coefficients, the analytical model used for analyses, core parameters that affect the peak reactor pressure or the probability of fuel rod failure, and the results of the transient analyses.

The NRC's acceptance criteria are based on GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to impair significantly the capability to cool the core.

Specific review criteria are contained in SRP Sections 15.4.8 and 4.2 (Appendix B). Other guidance is provided in Matrix 8 of RS-001.

The licensee used the following acceptance criteria for the analysis of the CEA ejection event:

1. Fuel failures due to DNB and fuel centerline melt (FCM) should be limited, so as not to impair the capability to cool the core. Additionally, the fuel failures should be within the limits of the fuel failures used in the radiological analysis.

2. Peak RCS pressure must remain below that which would cause the stresses in the RCS to exceed the faulted condition stress limits, and

3. Maximum average fuel pellet enthalpy at the hot spot must maintain below 200 cal/g.

Appendix B to SRP Section 4.2 provides the following interim acceptance criteria for reactivity initiated accidents (e.g., CEA ejection):

For Fuel Coolability

1. Peak radial average fuel enthalpy must remain below 230 cal/g.

2. Peak fuel temperature must remain below incipient fuel melting conditions.

3. Mechanical energy generated as a result of (1) non-molten fuel-to-coolant interaction, (2) fuel rod burst must be addressed with respect to RCPB, reactor internals and fuel assembly structure integrity.

4. No loss of coolant geometry due to (1) fuel pellet and cladding fragmentation and dispersal and (2) fuel rod ballooning.

For Fuel Cladding Failures

The high cladding temperature failure criterion for zero power conditions is a peak radial average fuel enthalpy greater than 170 cal/g for fuel rods with an internal pressure at or below system pressure, and 150 cal/g for fuel rods with an internal rod pressure exceeding system pressure. For intermediate (greater than 5 percent rated thermal power) and full power conditions, fuel cladding failure is presumed if local heat flux exceeds thermal design limits (e.g., DNB).

Appendix B to SRP Section 4.2 also provides fuel rod cladding failure thresholds due to pellet/cladding mechanical interaction (PCMI) as a function of cladding corrosion and increase on radial average fuel enthalpy (Δcal/g).

St. Lucie 2 current license basis does not include consideration of cladding failure due to PCMI. Input to dose analyses is based on estimates of fuel rod failure due to DNB and fuel centerline melting temperature. This approach continues to be acceptable based upon the conservative nature of the analytical methods used to predict the control rod ejected worth and local peaking factors (compared with 3-dimensional core physical methods).

St. Lucie 2 continues to employ a core coolability criterion of 280 cal/g peak radial average fuel enthalpy. As documented in Appendix B to SRP Section 4.2, the NRC staff no longer considers 280 cal/g an acceptable upper bound on fuel enthalpy to ensure coolable geometry. For the purpose of this review, the NRC staff will consider the interim criteria identified above.

Technical Evaluation

The analysis of the CEA ejection event is discussed in St. Lucie 2 FSAR 15.4.8 and licensing report Section 2.8.5.4.6 (Reference 2).

The licensee performed the CEA ejection accident with the methods documented in an NRC-approved Westinghouse Topical Report, WCAP-7588 (Revision 1-A) (Reference 55): the TWINKLE spatial neutron kinetics code (documented in WCAP-7979-P-A, 811016039) was used for an average core calculation; and FACTRAN (documented in WCAP-7908-A, ADAMS Accession No. ML080630436) was used for a hot spot analysis.

The licensee analyzed two sets of cases for the accident initiated from HFP of the uprated power level, at BOC and EOC, and two sets of cases initiated form HZP based on BOC and EOC kinetics. Table 2.8.5.4.6-1 of the licensing report (Reference 2) listed the values of the initial plant parameters (including ejected rod worth, delay neutron fraction, and Doppler Power defect). The analysis used a minimum value for the delayed neutron fraction, a maximum value of ejected CEA worth and minimum value of the Doppler power defect, which conservatively resulted in a higher nuclear power increase rate and a maximum amount of energy deposited in the fuel following CEA ejection. The analysis also used a positive MTC for the HZP-BOC case because a positive MTC resulted in positive reactivity feedback and thus increased the magnitude of the power increase. The analysis credited the variable high power trip (a high setting for HFP cases and lower setting for HZP cases) to trip the reactor. The NRC staff determined that the above assumptions were acceptable, since the selected values were bounding of the listed EPU nuclear design parameters.

The results of the CEA ejection in licensing report Table 2.8.5.4.6-3 (Reference 2) indicated that:

1. The calculated values of maximum fuel pellet enthalpy for the four analyzed cases were 151.4 cal/gm for HFP-BOC, 78.2 cal/gm for HZP-BOC, 141.3 cal/gm for HFP-EOC and 88.7 cal/gm for HZP-EOC. These calculated values of peak fuel enthalpy were less than the

acceptance criterion of 230 cal/gm specified in Appendix B to SRP Section 4.2. The calculated values also fell within the Westinghouse-specified analysis limit of 200 cal/gm.

2. For all cases the peak hot-spot fuel centerline temperature remained below the fuel melting temperature, and there were no fuel failures due to fuel melted.

3. The maximum rods-in-DNB was less than 9.5 percent of the fuel rods in the core. This value of the DNB fuel failure was consistent with that in the analysis of record for the CEA ejection event.

While no part of the St. Lucie 2 licensing basis, the NRC staff did not believe that consideration of PCMI fuel cladding failure would promote an increase in the radiological consequences. This position was based on the following considerations:

1. Due to TS power dependent CEA insertion limits (PDIL), only the HZP cases would have the potential to result in a prompt critical power excursion. The results of the EPU CEA ejection analysis indicated that the predicted increase in fuel enthalpy (△cal/g) for the BOC and EOC HZP cases remained well below the PCMI failure threshold provided in Appendix B to SRP Section 4.2. Therefore, no additional fuel failures would be expected due to PCMI for the HZP cases.

2. The at-power CEA ejection scenarios exhibited a significant wider power pulse relative to the prompt critical excursion prototypical to a reactivity insertion accident (RIA). The bounding ejected rod worth for the HFP event remained below $1 (i.e., $\Delta\rho/\beta < 1.0$). For the HFP scenario, the characteristics of the wider power pulse would promote margin relative to the empirically-based PCMI failure threshold (e.g., allowing cladding temperature to increase during the event). In addition, maximum ejected rod worth was based on control rod clusters residing in lower burnup, more reactive fuel assemblies. Predicted ejected rod worth of a control rod cluster residing in a higher burnup, less reactive fuel assembly would be significantly lower—promoting a more benign transient power excursion.

3. The radiological consequences conservatively assumed an activity level of 10 percent fuel failure (9.5 percent DNB failed fuel rods and 0.5 percent fuel centerline melt failed fuel rods). The results of the EPU CEA ejection analysis indicated that rods-in-DNB were less than 9.5 percent and no fuel centerline melt failed fuel rods. Hence, there was conservatism within the dose calculations to accommodate the unlikely scenario where PCMI would lead to fuel cladding failure in any fuel rods not already predicted to experience cladding failure (via DNB and fuel centerline melt) during a HFP, non-prompt power excursion.

With respect to coolable geometry, the results of the CEA ejection analysis indicated that the peak radial average fuel enthalpy remained below 230 cal/g (criterion # 1) and fuel temperature remained below melting temperature (criterion #2), which assured no fuel cladding failure to occur during a CEA ejection. Therefore, coolability criteria #3 and #4 were met.

In addition, based on the generic assessment in a NRC-approved Topical Report, WCAP-7588 (Revision 1-A, ADAMS Accession No. ML120960136), “An Evaluation of Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetics Methods,” the peak pressure would be less than that which would cause stresses to exceed the faulted condition stress limits (licensing report Page 2.8.5.4.6-5). Since the ejected rod worths used in the EPU analysis were bounded by the values used in the WCAP-7588 (Revision 1-A) analysis, the NRC staff agreed with the licensee that the WCAP-7588 (Revision 1-A) overpressure analysis remained valid at the EPU conditions.

The number of rods in DNB (FSAR, Section 15.4.8.5), based on generic assessment in WCAP-7588 (Revision 1-A), would be expected not to exceed 9.5 percent, which was used in the dose analysis.

Since the analysis was performed with the NRC-approved method, the values of the input parameters used were conservative, resulting in a maximum amount of energy deposited in the fuel following CEA ejection, and results showed that applicable acceptance criteria specified in SRP Sections 15.4.8 and 4.2 (Appendix B) were not exceeded, the NRC staff concluded that the analysis of the CEA ejection accident met the GDC 28 requirements and was acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the rod ejection accident and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The 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 EPU. Therefore, the NRC staff determines that the proposed EPU is acceptable with respect to the rod ejection accident.

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

Regulatory Evaluation

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

The NRC staff's review covered:

(1) The sequence of events,
(2) The analytical model used for analyses,
(3) The values of parameters used in the analytical model, and
(4) The results of the transient analyses.

The NRC's acceptance criteria are based on:

(1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;

(2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during AOOs; and

(3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

Specific review criteria are contained in SRP Sections 15.5.1 - 15.5.2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Licensing report Section 2.8.5.5 discusses the events of the inadvertent ECCS Actuation and CVCS malfunction that increases reactor coolant inventory.

An inadvertent actuation of the ECCS at power event, an AOO, could be caused by operator error or a false electrical actuating signal. During power operations, the high pressure safety injection pumps are incapable of delivering flow to the RCS because the pumps' shut-off head is less than the normal RCS operating pressure of 2250 psia. Therefore, the inadvertent operation of the ECCS at power event is not a credible event and is not analyzed by the licensee for EPU. The licensee's position of not analyzing the event and the associated bases are consistent with that discussed in FSAR Section 15.5.1 and therefore, are acceptable.

The CVCS malfunction that increases RCS inventory is an AOO that is evaluated for the effects of adding water inventory to the RCS. This event could be caused by operator error or a failure in the pressurizer level transmitter which causes an erroneous low-low signal. The generated signal will be transmitted to the controller which responds by actuating a second charging pump and closing the letdown flow to control valve to its minimum flow position. Section 2.8.5.5 of licensing report (Reference 2) presents the analysis of the limiting case, the CVCS malfunction initiated from full power caused by an erroneous pressurizer low-low signal that actuates a second charge pump and closes the letdown flow control valve to its minimum position. This assumption of initiating event is consistent with the AOR discussed in Section 15.5.3.2.2 of the FSAR, and therefore, is acceptable. The licensee analyzed this event using the NRC-approved RETRAN code to demonstrate that operators have 20 minutes to prevent the pressurizer from overfilling with water following a pressurizer high level alarm (PHLA) at minimum sepoint of 70 percent of tap span. The licensee's use of the RETRAN for the analysis is acceptable since the RETRAN is an NRC-approved code for St. Lucie 2's use in the analysis of non-CSs. The NRC staff also found that the credited operation action time of 20 minutes was acceptable with the bases discussed in the later part of this Section.

The licensee utilized the following initial plant conditions and assumptions:

- an initial reactor power of 3030 MWt based on a uprated core power of 3020 MWt, with 0.3 percent uncertainty (the RCS pump heat of 20 MWt was added to the core power), the RCS pressure of 2180 psia based on the low end of the allowable range (2225 psia) minus 45 psi measurement uncertainty, and the vessel average temperature (T_{avg}) of 581.5 °F based on the nominal high T_{avg} (578.5 °F) plus the T_{avg} measurement uncertainty of 3 °F.

- a maximum SG tube plugging level of 10 percent.

● the pressurizer sprays and heaters in the automatic mode.

● a PSV setpoint of 2425 psia with inclusion of a -3 percent tolerance.

● a PHLA setpoint of 70 percent of tap span, which included the level uncertainty.

● maximum reactivity feedback conditions were assumed.

● a total charging flow of 94 GPM based on the maximum total flow of 98 gpm for two charging pumps reduced by 4 gpm for the RCP bleed-off flow.

The above assumptions were acceptable since they were selected by the licensee in generating a maximum pressurizer water mixture volume during the transient for the EPU conditions.

The analysis assumed an initial pressurizer water level of 60 percent based on the nominal level (63 percent) minus the level measurement uncertainty (3 percent). In the response to RAI SRXB-70 (Reference 11), the licensee indicated that the nominal level minus uncertainty was used to delay the time to the PHLA setpoint and thus, maximized the charging flow injected prior to operator actions. The operators would be alerted to a RCS inventory increase event by either a HPPT or the safety grade PHLA. In the analysis, it assumed 20 minutes after either HPPT or the PHLA, the operators would mitigate the event by reducing or stopping charging flow and or restoring letdown flow. If a higher value of the initial pressurizer water level were used, the event would result in an early PHLA actuation. The earlier PHLA actuation would not result in a worst maximum pressurizer level, since in either case, the operator action would occur within 20 minutes from the actuation of the PHLA given the same charging flow injection. Therefore, the NRC staff agreed with the licensee that the values used for the initial pressurizer level would not significantly affect the maximum pressurizer water during the event and that the assumed value was acceptable.

Operator Action Time of 20 Minutes

When the licensee addressed the RAI SRXB-71 (Reference 56) regarding the basis of the 20 minutes assumed for operator action delay time, it indicated that the operator action time of 20 minutes was conservative with respect to the acceptance criteria technical rationale in the SRP 15.5.1 - 15.5.2, Section II, “Acceptance Criteria,” which stated that “The analysis objective is to show that the pressurizer does not become water-solid before the operator can terminate the transient, usually at about ten minutes (or longer) after the event begins.” The assumed 20-minute operator action time was also consistent with that of the AOR in FSAR Section 15.5.2. The licensee indicated that prevention of pressurizer overfill due to a CVCS malfunction was included in its licensed operator continuing training (LOCT). These tasks were contained in the licensee’s training department’s simulator evaluation and practice exercise guides. Training department required satisfactory completion of these tasks during the course of the LOCT program at the frequency specified in the LOCT task list. For event involving a reactor trip, operators were required to enter 2-EOP-01, “Standard Post Trip Actions.” One of the first few steps performed by operators in this procedure was the determination that RCS inventory control acceptance criteria were met, which included restoring and maintaining presurizer level between 30 and 35 percent. The licensee indicated that based on its last set of licensed operator simulator evaluations, the average time to complete the instructions in 2-EOP-01 was 13.8 minutes. This time period included completion of all steps, contingency actions, diagnosis, and transition briefing to direct crew to an optimal EOP for event mitigation. For events without involving a reactor trip, operators would be responding to a HPLA. The licensee's "Conduct of Operations" procedure required operators to announce the alarm to the control room supervisor using 3-way communication and to take prompt action to identify the cause of the unexpected alarm. For a HPLA, the annunciator response procedure noted that the alarm could be caused by rapid load change, malfunction of the pressurizer level control system or a charging/letdown flow mismatch due to letdown valve failure, and it directed operators to the abnormal operating procedure for pressurizer pressure and level, which provided instructions to stop charging if letdown was lost for any reason and provided guidance to deal with pressurizer level anomalies. The annunciator response procedure provided reasonable assurance that a prompt operator response would occur well within the 20-minutes assumed in the analysis. The NRC staff determined that the assumption of a 20-minute action time was acceptable since it was consistent with that assumed in the AOR, exceeded the SRP acceptance criterion of 10 minutes, and was supported by plant procedures and operator training records.

The event was analyzed to address the concerns of the pressurizer overfill and thus, it was assumed to occur without increasing or decreasing the primary coolant initial boron concentration. The case of a CVCS malfunction that caused a boron dilution was discussed in above Section 2.8.5.4.5 of the SER. In the analysis, the assumed single failure was the complete closure of the letdown flow control valve that occurred concurrently with the start of the second charging pump. The single failure assumption was consistent with the assumptions used in the AOR, and therefore, was acceptable.

The results of the analysis demonstrated that the pressurizer volume did not become water solid prior to 20 minutes after the PHLA was actuated, assuring that no water was discharged through the PSVs.

During the CVCS malfunction the changes in core power, RCS temperatures and RCS mass flow were small. With respect to peak RCS and main steam system pressures, the event was bounded by the loss of condenser vacuum event, which was analyzed with assumptions that were made to conservatively calculate the RCS and main steam system pressures and met the RCPB limits as discussed in above Section 2.8.5.2.1 of this SER. With respect to the fuel damage because of low DNBR, the event was bounded by the CEA withdrawal at-power, which was analyzed with assumptions that were made to conservatively calculate the minimum DNBR and met the DNBR SAL as discussed in above Section 2.8.5.4.2 of this SER.

Therefore, the NRC staff concluded that the analysis met the acceptance criteria of SRP Section 15.5.2 with respect to the acceptance criteria of the maximum pressurizer water level, peak RCS and main steam system pressures, and DNBR SAL, and thus, was acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the CVCS malfunction 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, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff determines that the proposed EPU is acceptable with respect to the analysis of the CVCS malfunction event.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of Pressurizer Pressure Relief Valve

Regulatory Evaluation

The inadvertent opening of a pressure relief valve results in a reactor coolant inventory decrease and a decrease in RCS pressure. A reactor trip normally occurs due to low RCS pressure.

The NRC staff's review covered:

(1) The sequence of events,
(2) The analytical model used for analyses,
(3) The values of parameters used in the analytical model, and
(4) The results of the transient analyses.

The NRC's acceptance criteria are based on

(1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;

(2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and

(3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

Specific review criteria are contained in SRP Section 15.6.1 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

An accidental depressurization of the RCS may occur as a result of an inadvertent opening of both of the pressurizer PORVs, an inadvertent opening of a single PSV, or a malfunction of the pressurizer spray system. This event results in a decrease in the RCS pressure. The depressurization of the RCS can cause the fuel to approach to the DNBR SAL. Pressurizer level increases initially due to expansion caused by depressurization and then decreases following reactor trip, which is actuated by a TM/LP trip signal. After the reactor trip, the event will be terminated with operator action by closing the affected PORVs block valves and controlling the pressurizer level by throttling the HPSI flow following the plant procedures.

The PSV at St. Lucie 2 is sized to discharge approximately half the steam flow rate of a PORV, and the operation of the pressurizer spray system at the full capacity cannot depressurize the RCS at the rate of two open PORVs. The licensee analyzed the event of opening of both

PORVs, which is the limiting depressurization case from inadvertent opening of PORVs (IOPORV), resulting in a lowest value of DNBR. The results of the IOPORV analysis are provided in licensing report Section 2.8.5.6.1.

The licensee used the NRC-approved computer codes to analyze this event: RETRAN calculated the RCS power, P-T; and VIPRE calculated the DNBRs. In the analysis, the initial reactor power and RCS temperature were assumed to be at their nominal values, the initial RCS flow rate was assumed at a value consistent with the minimum measured flow rate and the initial RCS pressure was assumed at a value consistent with the minimum value allowed by the plant TSs. Uncertainties in initial conditions were statistically included in the calculation of the DNBR limit using the methods described in an NRC-approve Westinghouse report, WCAP-11397-P-A (ADAMS Accession No. ML080630437), "Revised Thermal Design Procedures." The analysis used a least negative DPC such that the resultant amount of negative feedback was conservatively low in order to maximize any power increase due to moderator reactivity feedback. It also assumed a conservative moderator temperature coefficient (MTC) of 0 pcm/°F at HFP conditions. The analysis did not consider the spatial effect of voiding due to local or subcooled boiling with respect to reactivity feedback or core power shape. The assumptions related to the above DPC, MTC and void reactivity feedback were conservative, resulting in higher core power and lower minimum DNBR, and were acceptable.

The results of the analysis showed that the RCPB limits were met, since the RCS pressure decreased continuously throughout the transient, and that actuation of the TM/ LP reactor trip provided adequate protection against fuel failures, since the minimum DNBRs were above the DNBR SAL, thus ensured that no fuel damage would occur for this event.

Since the acceptable methods and adequate assumptions were used in the analysis, and the results of the analysis showed that the no RCS pressure would exceed the RCPB limits, and no calculated DNBR values would fall below safety DNBR limit, the NRC staff concluded that the analysis met the acceptance criteria of SRP Section 15.6.1 with respect to the pressure limits and core DNBR SAL, and, was acceptable.

During the review, the NRC staff noted that the analysis of the IOPORV event was performed to show that the DNBR did not exceed the safety DNBR limit and the analysis covered a short duration of the transient. The analysis did not show whether the pressurizer would fill to a water solid condition. In addressing the NRC staff's concern, the licensee reanalyzed the IOPORV event by extending the end time of the transient beyond that required to fill the pressurizer to a water solid condition and presented the results on pages 59 through 66 of L-2012-150 (Reference 50). This analysis was based upon the opening of only one PORV. This assumption was consistent with the definition of an AOO, which was specified as an occurrence initiating with a single fault (i.e., a single fault in the PORV control system). It was also conservative, since the smaller relief rate would allow the safety injection system to fill the pressurizer sooner. The analysis did not credit any operator action to terminate the RCS depressurization.

A set of sensitivity study was conducted to determine the impact of various input conditions on the time to fill. Table IOPORV-1 of L-2012-150 (Reference 50) provided the final set of analysis input assumptions for the most limiting (shortest) time to fill the pressurizer. The licensee provided the results of the pressurizer overfill analysis in the Table IOPORV-2 and Figures IOPORV-2 through IOPORV-3. The result showed that: (1) a reactor trip on the TM/LP trip signal was generated at 32.2 seconds, which was later than 16.9 seconds predicted for the

DNBR case in licensing report Section 2.8.5.6.1, since the reanalysis was based on opening of one PORV vs. two PORV assumed for the DNBR case; (2) the SIAS was actuated at 40.9 seconds; the RCS pressure continued to fall throughout the transient, and the falling RCS pressure led to an increasing safety injection (SI) delivery rate; (3) the pressurizer water volume decreased as steam was relieved through the PORV; the rate of decrease accelerated when the reactor was tripped, and continued until SI water began to enter the RCS and then the pressurizer water volume began to increase; and (4) the pressurizer filled to a water solid condition at 173 seconds.

The IOPORV event, when viewed from the mass addition perspective, could be evaluated in two phases: (1) an inadvertent opening of a pressurizer relief valve, followed by (2) an inadvertent ECCS actuation.

In the first phase, this event could be mitigated by closing the open pressurizer relief valve. If the valve could not be closed, then its block valve could be closed. Closing a pressurizer relief valve was a simple, prompt action.

The licensee indicated that the IOPORV event would result in one or more of the following control room annuciators:

1. H-9 - PZR CHANNEL X PRESS HIGH/LOW
2. H-10 - PZR CHANNEL Y PRESS HIGH/LOW
3. H-16 - QUENCH TANK PRESS HIGH
4. H-17 - PZR CHANNEL X LEVEL HIGH/LOW
5. H-18 - PZR CHANNEL Y LEVEL HIGH/LOW
6. H-20 - PORV V1475 RELIEF LINE TEMP HIGH
7. H-24 - QUENCH TANK TEMP HIGH
8. H-29 - PZR PROPORTION HTR LOW LEVEL TRIP/INTERLOCK
9. H-30 - PZR BACKUP HTR LOW LEVEL TRIP/SS ISO/INTLK
10. H-32 - QUENCH TANK LEVEL HIGH/LOW
11. H-36 – PORV V1474 RELIEF LINE TEMP HIGH
12. LC-1 – PZR PORV/SAFETY OPEN

The annuciator response procedures for the above alarms would provide direction to the operator to go to abnormal operating procedure, 2-AOP-01.10, “Pressurizer Pressure and Level.” The first immediate operator action for 2-AOP-01.10 is to verify that operating pressure is stable. The first contingency action requires determining if a PORV is open or leaking and provides direction to place the PORV in OVERRIDE and close the PORV block valve. The licensee’s simulator excise for the IOPORV event showed that the operator could close an open PORV in 10 seconds. Since an open pressurizer relief valve could be closed before SI actuation that occurred at 40.9 seconds, the IOPORV transient would end with little or no SI delivery to the RCS, and the pressurizer overfill would not be a concern.

If the operator did not close the pressurizer relief valve before the SI system was actuated, at 40.9 seconds, then the event would enter the second phase. In the second phase, actuation of the SI system was added. It would become necessary to shut off the charging flow, as well as close the open pressurizer relief valve. The HPSI flows, if not terminated by the operator, would end when the RCS was pressurized, by the ECCS flow, to the shut-off head of the HPSI pumps. The pressurizer fill rate would be determined mainly by the charging flow rate. This would increase the amount of time that would be available to shut off the charging flow.

If, for example, the operator closed the pressurizer relief valve at the time that SI was actuated, then there would be no SI delivery, according to the analysis results, since the RCS pressure would not have depressurized to below the shutoff head of the HPSI pumps. Meanwhile, the pressurizer level dropped below the nominal pressurizer water level. Therefore, the time to fill the pressurizer, under these circumstances, would be greater than the time (more than 26 minutes) predicted by the inadvertent ECCS actuation analysis discussed in licensing report Section 2.8.5.5, which was based upon a higher pressurizer level and a maximum flow rate of 94 gpm from two available charging pumps. Therefore, the time available to the operator, to shut off the flow from two charging pumps, would range from 173 seconds, if the pressurizer relief valve was not closed, to more than 26 minutes (in accordance with the results shown in licensing report Figure 2.8.5.5.1-4, "CVCS Malfunction at Power - Pressurizer Water Volume.")

If the operator did nothing, then the pressurizer would fill in 173 seconds. This would be the most pessimistic scenario. The NRC staff did not consider this would be likely to occur, since it required the operator to take no action, at all, for about three minutes.

The NRC staff found that (1) the St. Lucie 2 multiple alarms were available for operator to detect occurrence of the IOPORV event, (2) plant procedures provided clear direction to the operator to close the open PORV, and (3) the licensee's simulator exercise showed that closing the open PORV could be completed in 10 seconds, which was earlier than the SI actuation occurred at 40.9 seconds, and thus, would end the IOPORV transient with little or no SI delivery to the RCS. Based on its findings, the NRC staff determined that the above pressurizer overfill analysis, available alarming system, and procedures in combination with simulator exercise result had provided reasonable assurance that the pressurizer would not be expected to fill to a water solid condition that could prevent the PORV or PSV from closing after they were open, and thus, supported that the event would not generate a more serious plant conditions (such as unisolable SBLOCA), meeting the third AOO acceptance criterion.

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent opening of a pressurizer pressure relief valve event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the all AOO acceptance criteria are satisfactorily met. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff determines that the proposed EPU is acceptable with respect to the analysis of the inadvertent opening of a pressurizer pressure relief valve event.

2.8.5.6.2 SG Tube Rupture (SGTR)

Regulatory Evaluation

A SGTR event causes a direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and main steam safety or atmospheric relief valves. RPS and ESFs are actuated to mitigate the accident and restrict the offsite dose to within the guidelines of 10 CFR Part 50.67, "Accident source term."

The NRC staff's review covered:

(1) Postulated initial core and plant conditions,
(2) Method of T-H analysis,
(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 accident analysis.

The NRC staff's review of the consequences of the SGTR event focused on the T-H analysis of the SGTR in order to: (1) determine whether the calculated mass releases, which are input to the dose analysis, would be conservative (i.e., would lead to the highest dose releases); and (2) confirm that the faulted SG did not experience an overfill. Preventing SG overfill is necessary in order to keep the main steam lines intact, which prevents the dumping radioactive liquid releases to the environment. It also validates the SGTR mass release analysis assumption that only steam is released.

The review criteria for this event are set forth in SRP Section 15.6.3. Additional guidance is provided in SRP 15.0.1, Revision 0, "Radiological Consequence Analyses Using Alternative Source Terms," and RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors." The additional guidance is more relevant to the St. Lucie 2, since the radiological consequence analyses discussed in Section 2.9 of the licensing report (Reference 2) are based on an AST. Accordingly, the NRC staff has reviewed the licensee's SGTR analyses to determine whether there is reasonable assurance that the SGTR analysis, which provides input to the radiological consequences analysis, is appropriately conservative.

Other applicable regulations are

(1) Part 50.34 of 10 CFR Part 50, "Contents of construction permit and operating license applications; technical information," requires that safety analysis reports be submitted that analyze the design and performance of SSCs of the facility with the objective of assessing the risk to public health and safety resulting from operation of the facility and including determination of the margins of safety during normal operations and transient conditions anticipated during the life of the facility, and the adequacy of SSCs provided for the prevention of accidents and the mitigation of the consequences of accidents. As part of the licensing application process, licensees perform SE to ensure that their safety analyses remain bounding or continue to meet the applicable acceptance criteria for the licensing application conditions. To achieve the goals, licensees confirm that key inputs (such as neutronic and thermal hydraulic parameters) to the safety analyses are and will remain conservative with respect to the current design bases. If key safety analysis parameters are not bounded, a reanalysis or re-evaluation of the affected transients or accidents is performed to ensure that the applicable acceptance criteria are satisfied.

(2) Regulatory Position 1.3.2 specified in RG 1.183 states that an analysis is considered to be affected if the proposed modification changes one or more assumptions or inputs used in that analysis such that the results, or the conclusions drawn on those results, are no longer valid.

(3) Section 5.1.3 in RG 1.183 states that the numeric values that are chosen as inputs to the analyses should be selected with the objective of determining a conservative postulated dose.

Technical Evaluation

An SGTR accident, an ANS Condition VI event, results in passage of radioactive reactor coolant to the shell side of the SG through the ruptured SG tube, and ultimately, into the atmosphere. Therefore, the SGTR analyses for the proposed power uprate were performed to show that the resulting onsite and offsite doses stayed within the allowable guidelines and there was margin available to provide reasonable assurance that SG overfilling is unlikely. The margin-to-overfill (MTO) analysis of an SGTR event is used to validate the assumption that the SG would not overfill and to support the assumption that only steam releases would be released during an SGTR event. The steam releases analysis is used to calculate the steam releases, from the SGs, that are used as input in the dose analysis that is used to show that the applicable dose limits are met. The NRC staff's evaluation of the dose analysis is documented in Section 2.9 of this SER.

2.8.5.6.2.1 Steam Release Analyses for a SGTR Event

This analysis, discussed in Section 2.8.5.6.2 of licensing report (Reference 2), calculated the steam releases to atmosphere, which are input to the radiological doses analyses. During the course of the review, the NRC staff requested the licensee to provide additional information regarding analytical method, input values and mitigation procedures in support of acceptance of the mass release analysis. The licensee provided its response to RAI SRXB-08 (Reference 57). The NRC staff's evaluation of the mass releases analysis and the associated response is discussed as follows.

Computer Code and Methods Used for the Mass Releases Analysis

The SGTR event was analyzed with an NRC-approved code, RETRAN documented in WCAP-14882-A (ADAMS Accession No. ML093421329). Also, the methods discussed in FSAR Section 15.6.3 were maintained for the SGTR analysis. Therefore, the NRC staff determined that the computer code and methods remained acceptable for use of the mass release analysis.

From the event initiation to isolation of the affected SG (at 45 minutes), the cooldown rate, the total break flow, and steam releases from the affected and intact SG were calculated by the T-H analysis using RETRAN. Subsequent to the isolation of the affected SG, the ADV in the intact SG was used to cool down the RCS. An energy balance was performed to determine the steam releases from 45 minutes to SDC conditions. The SDC entry temperature is 325 °F ($\pm$ 25 °F). For calculating conservative steam releases, the analysis assumed cooldown to a temperature of 212 °F. Steam releases for the period between the affected SG isolation and the RCS cooldown to 212 °F were calculated for various cooldown rates (20 °F/hr to 100 °F/hr). The calculated maximum steam releases based on various cooldown rates were used as input in the dose analyses. The NRC staff has accepted this approach.

Initial Conditions

The steam release analysis for a SGTR event was based on a double-ended break of a single SG tube at full-power. The break was assumed to occur at the cold end of the shortest tube such that the mass flow rate from the break was maximized. The enthalpy of the break flow was based on the RCS hot-leg, maximizing the flash of the break flow and thus, maximizing the dose consequences. A LOOP was assumed at reactor trip. This assumption resulted in the loss of steam bypass control system (SBCS) for removal of decay heat. Heat removal from the RCS was achieved by action of SG MSSVs until the time of operator action, at which time, the ADV in the intact SG was used for heat removal, resulting in steam releases to the atmosphere. If the offsite power were available, the steam would have been routed to the SBCS. The analysis used conservative values of the plant initial conditions that resulted in maximum steam releases. The values used in the analysis were discussed in the table on page 12 of FPL letter L-2011-44 (Reference 57). The analysis was based on the maximum EPU power level including pump heat and uncertainties. A higher power level would maintain a higher RCS temperature and pressure, which produced a higher break flow rate and flashing fraction. The higher power level also produced a higher stored energy and decay heat, which produced higher steam releases. Various initial parameters were set at nominal values plus uncertainties to maximize the mass release. These parameters included initial RCS average temperature, pressurizer pressure, and pressurizer water flow level. Maximum flow from two high pressure safety injection pumps was assumed to maximize RCS pressure, which produced a higher break flow rate. The maximized SG tube plugging level was assumed to reduce initial SG pressure and maximize the break flow. The main FW flow pumps were tripped on LOOP. The FW flow rate, on LOOP, rapidly decreased to zero, minimizing the SG inventory. The SG water level of the nominal value minus uncertainty was used. The assumptions of termination of the main FW and use of a lower SG initial water level resulted in a lower SG inventory, which increased the flash fraction and the amount of the steam release to the atmosphere, and thus were conservative. Automatic initiation of one of the AFW pumps on low SG level was assumed to prevent SG dry out on the intact SG.

As stated in licensing report Section 2.8.5.6.2.2.2, the setpoints of the MSSVs were based on the nominal setpoints minus 3 percent. This assumption maximized the steam release from the affected SG MSSVs and was acceptable.

The mass release analysis did not model the ADVs during the first 45 minutes of the SGTR event. However, operator errors or mechanical failures could result in opening of ADVs in both intact and affected SGs in the first 45 minutes. To address the impact of a stuck open ADV, the licensee performed a sensitivity study (in the response to RAI SRXB-08 (Reference 57)) assuming an ADV on the affected and intact SG kept open for 5 minutes. The ADVs are capable of automatic operation from the control room. Its operation is powered by EDGs in the event of a LOOP. Each ADV has a dedicated safety related motor-operated blocked valve, which may be used to isolate the ADV if it is stuck open. A stuck open ADV can be isolated in a short time, thus an ADV isolation time of 5 minutes was assumed in the sensitivity study. Since LOOP cases would result in increased steam releases, the sensitivity study considered ADV operation for LOOP cases with variation in the ADVs opening time (early opening (5 minutes) and late opening (30 minutes) after reactor trip). Both cases assumed the ADVs in the full-open position for the same time duration (5 minutes). The results of the study showed that during the time ADVs were open, the SG depressurization slightly increased, but the impact on the total mass release from the affected SG and the break flow was not significant. Also, the break flow and mass release from the affected SG up to 45 minutes from this study were comparable with that of the licensing report case, and below those used in the EPU licensing report dose analyses. Therefore, the NRC staff agreed with the licensee that the impact of stuck-open ADV was insignificant and the break flow and mass release in the first 45 minutes used in the dose analysis remained conservative.

Based on the above discussion, the NRC staff found that input values of the key parameters used in the analysis would result in maximum steam releases, and were conservative. Therefore the NRC staff determined that the input values were acceptable.

Operator Actions

St. Lucie 2 emergency operating procedures (EOPs) for the SGTR event specify the use of ADVs on both SGs for RCS cooldown. The RCS depressurization is slightly delayed from RCS cooldown which allows for termination of break flow and isolation of the affected SG. These EOP actions result in cooling the RCS to 510 °F while depressurizing the RCS to within 50 psi of the SG pressure. During the depressurization process, the RCS subcooling is required to be maintained. These actions of cooldown and depressurization result in a significant reduction in break flow and consequently the dose releases.

From 45 minutes to the time of SDC entry, the plant EOPs provide direction to operators for plant cooldown. 2-EOP-4, "Steam Generator Tube Rupture," directs operators to isolate the most affected SG and refers to 2-EOP-99, Appendix R, which directs operators to isolate AFW flow by ensuring that AFW pump discharge isolation valves are closed and that the steam supply to the turbine-driven AFW pump is isolated. In addition to isolating the most affected SG, the EOP safety function status check sheet (SFSCS) requires operators to monitor SG levels and maintain unisolated SG levels between 60 and 70 percent narrow range span (NRS). The SFSCS is required to be completed every 15 minutes and is commenced in step 1 of 2-EOP-4, which is identified as a continuous step. Once the affected SG is isolated, 2-EOP-4 directs operators to maintain level in the isolated SG at less than 90 percent NRS. The EOP provides the following methods to maintain SG level: (1) lowing RCS pressure to below isolated SG pressure (identified as the most preferred method; (2) blowing down the isolated SG to a monitor storage tank; (3) steaming the isolated SG to the condenser; and (4) steaming the isolated SG to atmosphere (identified as the least preferred method).

The licensee indicated that isolation of the affected SG is included in St. Lucie 2 licensed operator continuing training and is identified on St. Lucie's INPO-accredited licensed operator continuing training program task list at a frequency of every two years. The SGTR scenario is included as a simulator training exercise and isolation of an affected SG is accomplished by implementing 2-EOP-99, Appendix R. The licensee requires every licensed operator to participate in this exercise during the two year training program. In addition, there is a critical task contained in the St. Lucie training department's simulator evaluation guides and training department guidelines require satisfactory completion of critical tasks in order to receive a satisfactory grade during a simulator evaluation. Furthermore, the operator action time of 45 minutes represents an increase from the operator action time of 30 minutes included in current FSAR 15.4.4.5.4.

Based on the above discussion, the NRC staff determined that the licensee's procedures and training programs provide reasonable assurance that operators will take adequate actions for isolation of the affected SG, as assumed in the mass release analysis.

MTO for the Limiting Mass Release Case

At an audit of the St. Lucie EPU safety analysis, conducted by the NRC staff at Westinghouse facility in Rockville, Maryland on February 14 and 15, 2012, the NRC staff requested the licensee to provide a discussion of adequacy of the St. Lucie 2 procedures regarding operator actions that would be taken to avoid SG overfill during the period from 45 minutes to break flow termination for the limiting SGTR mass release case.

In response (pages 2 and 3 of Attachment 1 to FPL letter L-2012-150 (Reference 50)), the licensee indicated that at the end of the EPU SGTR event of 45 minutes, the mass release analysis discussed in licensing report Section 2.8.5.6.2 and Reference 5 predicted that the SG MTO was approximately 6,600 ft^3 and the primary to secondary ruptured tube leakage rate was approximately 35 lbm/sec, or 0.78 ft^3/sec. If the operator took no actions, it would take more than 2 hours (following the initial 45 minutes) to lose the available MTO. The licensee indicated that the operator actions required to be completed in the event of a SGTR event were provided in 2-EOP-04. One of the goals of the procedure was to maintain the isolated SG level less than 90 percent narrow range indication. As listed in the order presented in the 2-EOP-04, any of the following methods could be used:

- Lower RCS pressure to below the isolated SG pressure, thus enabling back flow. 2-EOP-04 identified this as the preferred method to control isolated SG level. The back flow method could be accomplished using safety-related equipment (i.e., use of charging pumps and auxiliary spray valves to depressurize the RCS);
- Blowing down the isolate SG to the monitor storage tanks;
- Steam the isolated SG to the condenser; and
- Steaming the isolated SG to the atmosphere via the ADVs. 2-EOP-04 noted that this was the least preferred method to control the isolated SG level. A caution note was also provided in the EOP stating “Steaming the isolated SG to atmosphere should only be performed as the least resort.”

Since the sufficient instructions in the EOPs were available to control and avoid SG overfill, and the action time of more than 2 hours was available for operators to cooldown the plant, terminate the break flow, and maintain the affected SG level less than 90 percent narrow range indication, the NRC staff agreed with the licensee that MTO in the affected SG would be available and no SG overfill was expected to occur, supporting the assumption of only-steam release used in the limiting mass release case.

Results of the Analysis

Table 2.8.5.6.2-1 of the licensing report (Reference 2) provided the results of the SGTR analyses for (1) steam releases via a turbine to condenser prior to reactor trip, (2) steam releases from reactor trip to 45 minutes when operator isolated the affected SG, and (3) the RCS break flow to the affected SG.

From 45 minutes to SDC, the cooldown rates of 100, 75, 38, 30, 25, and 20 °F/hr were assumed. The results of the steam releases analysis for various cooldown rates were provided in the table on page 16 of FPL Letter L-2011-441 (Reference 57). The maximum calculated steam releases based on various cooldown rates were used as input to the dose releases analysis which was document in licensing report Section 2.9. The NRC staff has accepted this approach.

From 45 minutes to 2 hours, the mass release rate was based on 100 °F/hr cooldown. The sensitivity study showed that this maximum cooldown rate maximized the steam released during the early part of the event and was conservative, resulting in maximum dose releases. From 2 hours to 8 hours, the RCS was cooled to SDC entry conditions of 300 °F. The licensee calculated that during this period the cooldown rate was 18.3 °F/hr, and thus, used the cooldown rate of 20 °F/hr to calculate the mass release for this interval. The steam releases from 8 hours to RCS conditions of 212 °F were determined using 20 °F/hr cooldown rate, since the sensitivity study showed that this slowest cooldown rate resulted in a maximum mass release. All the steam releases calculated by the T-H analyses discussed above were added by 10 percent for conservatism prior to the use in the dose analysis.

Based on its review of the mass release analysis discussed above, the NRC staff found that (1) the licensee's steam release analysis had adequately accounted for operation of the plant at the proposed EPU conditions, (2) the analysis was performed with appropriately conservative methods and a NRC-approved computer code, (3) the assumptions used in the analysis were conservative, resulting in maximum steam releases, and (4) the St. Lucie 2 EOPs and training program provided clear instructions for operators to isolate the affected SG and cool down the RCS to SDC conditions. Therefore, the NRC staff concluded that the steam release analyses, with consideration of St. Lucie 2 EOPs were acceptable for use in the SGTR dose calculations in support of the EPU application.

2.8.5.6.2.2 SG Margin-to-Overfill (MTO) Analysis for an SGTR Event

The analysis, discussed in Section 2.8.5.6.2 of licensing report (Reference 2), calculates the steam releases to atmosphere, which are input to the radiological doses analyses. In the analysis, the licensee used the initial conditions and assumptions to maximize the mass releases. The licensee claimed that while the SGTR analysis was not biased for SG overfill, the analysis showed sufficient margin to SG overfill to the operator action time of 45 minutes, and thus, considered only steam releases that carried radioactive material for the radiological dose analysis. However, the assumptions used in the mass release analysis in maximizing the mass releases would not result in maximum water levels in the affected SG, and therefore, would not be conservative with respect to the MTO analysis. The NRC staff judged that they will not be acceptable for the MTO analysis. If the affected SG fills with water (i.e., overfill), then, the water may spill into the steam lines. The weight of this water could cause the steam line(s) to break and discharge water into atmosphere. Water releases have a significantly greater concentration of radioactive material when compared with that of steam releases. Such a water discharge would invalidate the SGTR dose releases analysis. The results would be higher radiological releases.

The NRC staff requested an analysis, performed with acceptable code and based on a conservatively biased condition that would yield a minimum margin to SG overfill. In response, the licensee provided a discussion of a supplemental MTO analysis in the response to RAI SRXB-01 through SRXB-07 (Reference 57). The NRC staff has reviewed the MTO analysis and provided the evaluation as follows.

Computer Code Used for the MTO Analysis

As stated in the response to RAI SRXB-01, the MTO analysis was performed with the NRC-approved RETRAN code, which modeled the key parameter primary and secondary system components, RPS and engineered safety features actuation trips and core kinetics. The licensee included conservatisms in the following plant initial conditions:

Initial Conditions

The initial conditions, assumptions, and the associated bases were provided in Tables 2 through 4 of FPL letter L-2011-441 (Reference 57). The SGTR was based on a double-ended break of a single SG tube. LOOP was assumed at reactor trip. This assumption was conservative relative to offsite power available, since the assumption reduced energy transfer from the RCS primary to secondary side, which resulted in a higher RCS pressure, increasing break flow, thus, limiting MTO. The analysis used values of the plant initial conditions that resulted in a minimum MTO. Tables 2 through and 4 of FPL letter L-2011-441 (Reference 57) provided for each key parameter the nominal value, uncertainty, analysis value, and rationale for the selection of the value used in MTO analysis. The analysis was based on the power level of 3050 MWt, which is the proposed EPU power level plus calorimetric uncertainties and pump heat. Various initial parameters were set at nominal values plus uncertainties to minimize the MTO. These parameters included initial RCS pressure, pressurizer water flow level, and SIAS setpoint. A higher RCS pressure produced a higher break flow rate that resulted in a reduced MTO at the time operator terminated the AFW to the affected SG. Maximum flow for two safety injection pumps was assumed to offset break flow and maintain RCS inventory and pressure. The AFW actuation signal (AFAS) was set at 25.5 percent of the narrow range span (NRS), which was based on the nominal value of 20.5 percent plus 5 percent uncertainty. This assumption was conservative with respect to the MTO since an earlier AFAS time resulted in a higher integrated AFW which decreased the affected SG pressure, resulting in an increase in the break flow and the SG water level.

The MSSVs were set to minimum opening setpoints with maximum blowdown rate. The use of lower MSSV setpoints and higher blowdown rate would maintain a lower SG pressure and maximize break flow after reactor trip as well as increase AFW flow, which reduced the MTO.

The SG initial water levels are controlled by the plant SG level control program. The SG initial level is higher at the lower power levels. The analysis used a SG level of 60 percent NRS, which was based on the nominal value of 65 percent NRS at full-power minus uncertainty of 5 percent. Since the initiation of the AFW flow and subsequent termination of the AFW flow on the AFAS reset signal were based on fixed SG levels, the initial SG mass played no significant role in determining the minimum MTO. Using a higher initial mass delayed the AFW flow initiation; however AFW flow initiation would be at the same SG level setpoint, irrespective of the initial mass.

Single Failure Consideration on TD AFW

The analysis assumed that flow from both a motor-driven and turbine-driven AFW pumps was injected to the affected SG up to the a high reset level (based on the nominal value plus uncertainty discussed in Table 2 of FPL letter L-2011-441 (Reference 57)). The AFW reset logic would prevent AFW flow to the affected SG when the SG was above the setpoint. The use of a high reset setpoint resulted in a high integrated AFW flow to SG and minimized the MTO. As discussed in the response to RAI SRXB-01 of FPL letter L-2011-441 (Reference 57), the analysis assumed that the single failure used was a failure to close one AFW flow control valve on the affected SG. Specifically, the valve was assumed failed open on turbine-driven AFW pump after reaching the AFAS reset. The AFW control valves normally would open on AFAS and close at AFAS reset setpoint. Above a high value of the reset level, turbine-driven AFW rate was assumed to inject to the affected SG due to a single failure consideration. The turbine-driven AFW flow was terminated by operators with a delay time of 15 minutes. The increased AFW flow from the single failure reduced the MTO.

Based on the above discussion, the NRC staff found that input values of the key parameters used and the single failure considered were conservative, resulting in a minimum MTO, and therefore, determined that they were acceptable.

Operator Actions

The MTO analysis did not credit any operator action. If credited, several of the operator actions specified in EOPs would provide a greater MTO. The actions include:

- Initiation of a cooldown using SG ADVs - Following the isolation of FW flow, the operator is required by EOPs to initiate a plant cooldown by dumping steam through the ADVs. A cooldown of the RCS increases SG MTO as the coodown of the RCS combined with a depressurization will bring the primary and secondary sides to a temperature and pressure equilibrium, terminating SG tube break flow. In the analysis no cooldown of the RCS via operator action was credited in the first 45 minutes. As a result, break flow remained conservatively high throughout the event. This break flow in combination with continuing AFW flow resulted in a low SG MTO, and was conservative.

- Initiation of depressurization with pressurizer PORV - During the cooldown of the RCS, the operator is required by the EOPs to depressurize the RCS to within 50 psi of the affected SG pressure. This would minimize the break flow. In the analysis no operator action to depressurize the RCS was credited in the first 45 minutes. As a result, break flow remained conservatively high throughout the event. The continuing break flow in combination with maximum AFW flow resulted in a lower MTO.

The MTO analysis did not model the above operator actions to control SG water level, cooldown and depressurize the RCS, equilibrate RCS and affected SG pressures, and terminate break flow. The NRC staff agreed with the licensee that the MTO analysis predicted a conservative break flow rate relative to the break flow rate that would occur when operators initiate EOP actions to equilibrate RCS and affected SG pressure to terminate the break flow to the affected SG.

The only operator action directly accounted for in the MTO analysis was termination of TD AFW flow to the affected SG following AFAS reset when the affected SG NRS level reached a highest reset point, plus a 15 minute delay time. Since the AFAS reset logic would prevent AFW flow from injecting into the affected SG when the nominal SG level is above the nominal reset point, the value used in the analysis was the nominal value of the reset point plus uncertainty, resulting in a greater amount of the AFW injected to the affected SG, and thus, was conservative with respect to the MTO. The use of operator action time of 15 minutes was also acceptable based on adequate mitigation procedures and training program discussed in the response to RAI SRXB-SRXB-08 in FPL letter L-2011-441 (Reference 57) as follows:

- In the St. Lucie 2 EOPs, the acceptance criteria of the Safety Function Status Check Sheet, including SG water level, is required to be verified every 15 minutes;
- EOP-4 for SGTR includes steps for ensuring that SG levels are maintained within specified limits;

- EOP-99 Appendix R, “Steam Generator Isolation,” instructs operator to isolate AFW by ensuring AFW pump discharge isolation valves are closed and that the steam supply to the turbine-driven AFW pump is isolated (Either one of these actions is sufficient to terminate turbine-driven AFW flow to the affected SG).

Isolation of the affected SG is included in St. Lucie 2 licensed operator continuing training and is identified on St. Lucie’s INPO-accredited licensed operator continuing training program task list at a frequency of every two years. The SGTR scenario is included as a simulator training exercise and isolation of an affected SG is accomplished by implementing 2-EOP-99, Appendix R. The licensee requires every licensed operator to participate in this exercise during the two year training program. In addition, there is a critical task contained in the St. Lucie training department’s simulator evaluation guides and training department guidelines require satisfactory completion of critical tasks in order to receive a satisfactory grade during a simulator evaluation.

Results of the Analysis

The results of the analysis in page 1 of the attachment to FPL letter L-2011-441 (Reference 57) showed that for the total SG secondary side volume of 7984 ft^3, the MTO was greater than 1200 ft^3. This MTO calculated with conservative break flow would be sufficient to prevent SG overfill considering St. Lucie 2 EOPs that will direct operators to take actions to reduce the pressure difference between the RCS and the affected SG, which would reduce break flow.

Based on its review of the MTO analysis discussed above, the NRC staff found that (1) the licensee’s analysis had adequately accounted for operation of the plant at the proposed EPU conditions, (2) the analysis was performed with appropriately conservative methods and a NRC-approved computer code, (3) the assumptions used in the analysis were conservative, resulting in a minimum MTO, (4) the calculated MTO of greater than 1200 ft^3 at 45 minutes when operators isolated the affected SG, and (5) the St. Lucie 2 EOPs provided clear instructions for operators to isolate the affected SG, control the SG levels within specified limits, and cool down the RCS to SDC conditions. Therefore, the NRC staff concluded that the MTO analysis with consideration of St. Lucie 2 EOPs was acceptable to show a MTO during an SGTR event for the EPU application.

Conclusion

Based on its review, the NRC staff found that (1) the MTO analysis was performed with appropriately conservative methods and acceptable computer code, (2) the assumptions used in the analysis were conservative, resulting in a minimum MTO, and (3) the results showed that the SGTR event would not result in an overfill of the ruptured SG. Therefore, the NRC staff concluded that the MTO analysis was acceptable to show no-overfill to occur during an SGTR event, and the assumption of the only steam releases in the dose analysis remained valid. Also, the NRC staff determined that the mass release analysis was acceptable because it was based on acceptable methods and conservative assumptions.

2.8.5.6.3 Emergency Core Cooling System and LOCAs

Regulatory Evaluation

LOCAs are postulated accidents that would result in the loss of reactor coolant from piping breaks in the RCPB at a rate in excess of the capability of the normal reactor coolant makeup system to replenish it. Loss of significant quantities of reactor coolant would prevent heat removal from the reactor core, unless the water is replenished. The reactor protection and ECCS systems are provided to mitigate these accidents.

The NRC staff's review covered:

(1) the licensee's determination of break locations and break sizes;
(2) postulated initial conditions;
(3) the sequence of events;
(4) the analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients;
(5) calculations of PCT, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and LTC;
(6) functional and operational characteristics of the reactor protection and ECCS systems; and
(7) operator actions.

The NRC's acceptance criteria are based on:

(1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance;
(2) 10 CFR Part 50, Appendix K, insofar as it establishes required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA;
(3) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer;
(4) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and
(5) GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented.

Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance provided in Matrix 8 of RS-001 (Reference 1).

Technical Evaluation

2.8.5.6.3.1 Large Break LOCA

2.8.5.6.3.1.1 Methodology implementation and the analytical model

The licensee's LBLOCA analyses were performed by Westinghouse and provided to the NRC in Attachment 5 of L-2011-021. The LBLOCA analyses were performed using the Appendix K based "CENPD-132, Supplement 4-P-A, *Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model*," approved by the NRC on December 15, 2000. This is the same model that is used in the current AOR. The NRC staff reviewed the provided analysis and additional information provided to supplement the analysis and concluded that the licensee's implementation of CENPD-132 adheres to the limitations set forth in the SE.

NRC IN 2009-23, "Nuclear Fuel Thermal Conductivity Degradation," describes a recently identified issue concerning the ability of legacy thermal-mechanical fuel modeling codes to predict the exposure-dependent degradation of fuel thermal conductivity accurately. Some legacy codes, including FATES3B, non-conservatively over-predict fuel thermal conductivity at higher burnups. A safety concern with fuel TCD in a LOCA would be that fuel temperatures modeled incorrectly would affect the initial stored energy causing the LOCA evaluation model to predict potentially erroneous PCTs. The PCT for St. Lucie 2 occurs during the reflood phase of the transient, during which the decay heat is believed to be significantly more important than initial stored energy (NRC, "Quantifying Reactor Safety Margins: Application of Code Scaling, Applicability, and Uncertainty Evaluation Methodology to a Large-Break, Loss-of-Coolant Accident," NUREG/CR-5249, Rev. 4, December 1989, ADAMS Accession No. ML030380473). The methodology includes a 1.02 multiplier on decay heat as prescribed by Appendix K. To confirm that the effects of TCD will not drive the blowdown peak higher than the reflood peak the licensee provided a sensitivity study in L-2012-113 that demonstrates even with significant TCD the blowdown peak remains at least 250 °F below the limiting reflood PCT. In the case of St. Lucie 2 and the implementation of CENPD-132, Supplement 4 the staff finds that the licensee has acceptably justified not including a TCD correction for the LBLOCA evaluation.

Downcomer boiling is caused by metal heat release from vessel and core barrel walls to fluid in the downcomer gap. Metal heat from the vessel lower head and structures in the lower plenum also contribute to downcomer boiling. As heat is released to the downcomer fluid, its temperature is gradually increased, eventually subcooled, and saturated boiling takes place. Voids generated by these processes displace water in the downcomer and reduce the driving head that forces water into the core during the reflood phase of a LBLOCA. This loss in head can significantly reduce the core flooding rate, and increase the peak cladding temperature.

The staff questioned the treatment of downcomer boiling in the LBLOCA analysis. The licensee provided a response in L-2011-533. The staff had further clarifying discussions during the audit and the licensee submitted an additional response to address downcomer boiling, L-2012-131. The initial response stated that no degradation due to two phase downcomer boiling effects during the reflood calculation were calculated for any of the St. Lucie 2 EPU cases analyzed. The licensee stated that the CE plant design features very large SITs ensuring that the downcomer will be filled when the SITs inject leading to the no two phase flow degradation result. The initial response also stated that heat addition to the coolant in the downcomer and lower plenum from the reactor vessel wall and internals is considered. The staff was concerned that the core shroud may have been excluded as a heat source, but during the audit the staff reviewed a Westinghouse procedure that clarified that the internals include the core shroud. The licensee performed a sensitivity study to examine impact of a lumped wall heat model instead of the currently used semi-infinite slab wall heat model. The study demonstrated that the semi-infinite slab wall heat model transferred more heat to the downcomer fluid than the lumped wall heat model. The sensitivity study also demonstrated that for three different condensation scenarios the downcomer remained significantly sub cooled. The licensee also provided graphs of various flow rates into the downcomer vs time. These demonstrated that mixing in the downcomer would be promoted by the large amounts of cold water entering the downcomer. Additionally the licensee provided sensitivity studies where downcomer boiling was simulated and some known Appendix K conservatisms were removed. The study demonstrated that calculated PCT remained the limiting case. Based on the various sensitivity studies that did not reveal any more limiting cases and the unique design of the CE plant with very large SITs that will promote mixing the licensee has adequately accounted for downcomer boiling in the LBLOCA analysis.

Determination of break locations and break sizes

A spectrum of guillotine breaks in the RCP discharge leg were analyzed. The RCP discharge leg is the limiting break location because it maximizes the amount of spillage from the ECCS. The most limiting break size was the same as in the AOR.

Postulated initial conditions and sequence of events

The current rated thermal power for St. Lucie 2 is 2700 MWt plus 0.3 percent power measurement uncertainty. The assumed reactor core power used in the LBLOCA analysis is 3030 MWt. 3030 MWt represents 100.3 percent of the uprated power. The LBLOCA analysis also assumed a SG tube plugging level of 10 percent in all SGs, a peak linear heat generation rate (PLHGR) of the hot rod of 12.0 kW/ft, and a maximum integrated radial peaking factor of 1.6. The licensee stated that there was no change in methodology assumptions made from the current AOR to the EPU analysis. The staff questioned what conditions led to a decrease in PCT when compared to the AOR. The licensee provided a response in L-2011-533. The largest impacts to PCT were from core power increase, elimination of discretionary conservatism, and a decrease to the integrated radial peaking factor. The staff has reviewed the changes and found them to be consistent with the methodology and are therefore acceptable.

The licensee performed a study in accordance with the evaluation model to identify the limiting singe failure. It was determined that no-failure of the ECCS is the most limiting which is the same limiting case as in the AOR. No-failure of the ECCS leads to a maximum amount of SI spilled into containment, lowering containment pressure. Lower containment pressure leads to a slower core reflood rate and therefore a higher PCT.

2.8.5.6.3.1.2 Results

In Attachment 5 of L-2011-021, the licensee provided results for the St. Lucie 2 LBLOCA analyses. The calculated PCT, the maximum cladding oxidation (local), and the maximum core-wide cladding oxidation for the limiting 0.6 double-ended guillotine break in the RCP discharge leg (DEG/PD) are given in the following table.

	EPU Analysis	10 CFR 50.46 Limits
PCT	2087 °F	2200 °F (10 CFR 50.46(b)(1))
Maximum Local Oxidation	14.48 percent	17.0% (10 CFR 50.46(b)(2))
Maximum Total Core-Wide Oxidation (All Fuel)	<1 percent	1.0% (10 CFR 50.46(b)(3))
Peak Linear Heat Generation Rate	12.5 kW/ft	

During the audit on February 22 and 23,2012 the staff confirmed that in accordance with the methodology, the cladding oxidation model was initialized with a thin layer of pre-accident oxidation on both the inside and outside of the cladding regardless of the burnup that was analyzed. The Baker-Just correlation is required to be used to calculate the amount of cladding reacted. The results of the calculations identified in the table above demonstrate that the 10 CFR 50.46 criteria are met. Based on this, and on the fact that the licensee's model conforms to the required and acceptable features of ECCS evaluation models set forth in Appendix K to 10 CFR Part 50, the staff finds the licensee's LBLOCA analysis acceptable at the proposed EPU conditions.

2.8.5.6.3.2 Small Break LOCA

2.8.5.6.3.2.1 Methodology implementation and the analytical model

The licensee's SBLOCA analyses was performed by Westinghouse and provided to the NRC in Attachment 5 of L-2011-021. The SB LOCA analyses was performed using the Appendix K based CENPD-137, Supplement 2-P-A (S2M), "Calculative Methods for the ABB CE Small Break LOCA Evaluation Model," approved by the NRC on December 16, 1997. This is the same evaluation model that is used in the current AOR. The NRC staff reviewed the provided analysis and additional information provided to supplement the analysis and concluded that the licensee's implementation of CENPD-137 adheres to the limitations set forth in the SE.

Determination of break locations and break sizes

The staff questioned the appropriateness of the break spectrum used in the SBLOCA analysis. The licensee provided a more refined break spectrum analysis in L-2012-113. The severed injection line break has some significant differences from the other small breaks and therefore cannot be included in the assumptions about small break sizes greater than 0.06 ft^2/PD. In L-2012-131 the licensee provided an analysis of a severed injection line break. Neither additional analysis revealed any more limiting cases.

Postulated initial conditions and sequence of events

The current rated thermal power for St. Lucie 2 is 2700 MWt plus 0.3 percent power measurement uncertainty. The assumed reactor core power used in the SBLOCA analysis is 3030 MWt. 3030 MWt represents 100.3 percent of the uprated power. The SBLOCA analysis also assumed a SG tube plugging level of 10 percent in all SGs, a PLHGR of the hot rod of 13.0 kW/ft. The staff questioned the maximum RWST temperature used in the analysis. The licensee provided a response in L-2011-533. The maximum temperature used in the analysis is the maximum TS value plus 4 °F of uncertainty. The maximum RWST temperature is appropriate because it minimizes the cooling ability of the ECCS water delivered.

The single failure criterion required by Appendix K was satisfied by assuming the failure of an EDG. This failure provides minimum SI flow through the loss of one train of SI pumps—75 percent of the flow from one HPSI pump, 40 percent of the flow from one charging pump, and no LPSI flow is credited in the analysis. The licensee stated that there were no changes in methodology assumptions made from the current AOR to the EPU analysis.

2.8.5.6.3.2.2 Results

The table, below, provides results of the SBLOCA analysis at the uprated power.

Limiting Break Size	0.05 ft^2 Pump discharge	10 CFR 50.46 Limits
PCT	1903 °F	2200 °F (10 CFR 50.46(b)(1))
Max. Local Oxidation	9.21 percent	17.0 % (10 CFR 50.46(b)(2))
Max. Total Core-Wide Oxidation (All Fuel)	<0.94 percent	1.0 % (10 CFR 50.46(b)(3))

The results of the calculations identified in the table above demonstrate that the 10 CFR 50.46 criteria are met.

The staff concludes that the licensee's LOCA analyses are acceptable and demonstrate that St. Lucie 2 complies with the requirements of 10 CFR 50.46 (b)(1-4).

2.8.5.7 Anticipated Transients without Scrams

Regulatory Evaluation

An ATWS event is an AOO (such as loss of normal FW, loss of condenser vacuum or loss-of-offsite-power) combined with an assumed failure of the reactor trip system (RTS) to shutdown the reactor. On June 26, 1984, the NRC approved 10 CFR 50.62, "Requirements for reduction risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants (known as the "ATWS Rule")." This rule, as amended on July 6, 1984, November 6, 1986, April 3, 1989, July 29, 1996 and August 28, 2007, requires nuclear power plant facilities to reduce the likelihood of failure to shut down the reactor following AOOs, and to mitigate the consequences of an ATWS event. In general, the equipment to be installed in accordance with the ATWS rule is required to be diverse from the existing RPS, and must be capable of being tested at power.

The NRC staff's review was conducted to ensure that the above "ATWS Rule" requirements were met. In addition, the NRC staff verified that the consequences of an ATWS met the acceptance criterion in SRP (Revision 2), Paragraph 2.D of Section 15.8 (page 15.8-5), which specified that the peak primary system pressure during the ATWS event should not exceed the ASME Service Level C limit of approximately 3200 psig.

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.

Review guidance is provided in Matrix 8 of RS-001 and Chapter 15.8 of the SRP.

Technical Evaluation

The basic requirements for the PWRs manufactured by CE are specified in paragraphs (c)(1) and (c)(2) of 10 CFR 50.62 (ATWS Rule) which states, in part, that:

> Each pressurized water reactor must have equipment from sensor output to final actuation device, that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) FW system and initiate a turbine trip under conditions indicative of an ATWS

and

> Each pressurized water reactor manufactured by Combustion Engineering or by Babcock and Wilcox must have a diverse scram system from the sensor output to interruption of power of the control rods

As discussed in Section 2.8.5.7 of the licensing report for St. Lucie 2, a plant with a CE-manufactured reactor, has installed a safety-related diverse scram system (DSS) designed to be diverse and independent from the RPS to satisfy the ATWS Rule requirements for ATWS prevention. In addition, St. Lucie 2 has installed a diverse turbine trip (DTT) which is independent of the RPS and automatically initiates a turbine trip, as well as a diverse AFW actuation system (DAFAS) that is diverse from the RPS and automatically initiates the AFW system. The setpoint for DSS (2450 psia) is set above the RPS HPP setpoint (2415 psia) and below the PSV relief pressure setpoint (2575 psia). The DTT is actuated at a DSS trip signal and the DAFAS actuation in low SG level is synonymous with the AFAS setpoint as shown in TS Table 3.3-4, Function 7.c, SG 2A & 2B Level Low. The NRC previously reviewed and concluded (Reference 58) that the St. Lucie 2 DSS, DTT, and DAFAS designs were acceptable for compliance to 10 CFR Part 50.62.

For the EPU application, the licensee claimed that the setpoints for the required DSS, DTT, and DAFAS equipment remained valid; however, no ATWS analysis based on the EPU conditions was performed. Since the setpoints of the DSS, DTT, and DAFAS are based on the current power level conditions, they may not be adequate for the EPU conditions. During the course of the review, the NRC staff requested the licensee to provide information to demonstrate that the St. Lucie 2 ATWS response at EPU conditions would meet the RCS pressure limit acceptable to the ATWS analysis. In response, the licensee indicated (References 59) that previous ATWS analysis for CE plants identified that the loss of load (LOL) initiated at 2700 MWt and the loss of main FW (LOFW) initiated at 2560 MWt were the limiting ATWS events. The analysis showed that for the St. Lucie 2 class plants, a DSS with a 2450 psia trip setpoint and a 2-second response time would maintain the peak pressure in the range of 2600 psia.

The licensee referred to the analyses of the limiting AOO (LOCV) and postulated accident FLB in licensing report Section 2.8.5.2.1 and licensing report Section 2.8.5.2.4 (Reference 2), respectively to show that the setpoints of the DSS, DTT, and DAFAS at St. Lucie 2 were adequate to protect against overpressure during power operation at the proposed EPU level. Although the FLB event (a postulated accident) is not an AOO, it is used as a conservative representation of the LOFW, an AOO. As discussed in Table 1 of FPL letter L-2011-273 (Reference 59), both EPU LOCV and FLB analyses applied more conservative inputs and assumptions to maximize the peak RCS pressure than that were required in the ATWS analyses. Both EPU LOCV and FLB analyses were found acceptable with the bases discussed in Sections 2.8.5.2.1 and 2.8.5.2.4 of this SE report, respectively. The comparison of the ATWS and EPU analyses is discussed below:

For Loss of Load (LOL) -

- The ATWS LOL analysis assumed instantaneous termination of all FW flow and steam flow to the condenser, and the delayed reactor trip until the DSS setpoint of 2450 psia was reached. The peak RCS pressure was about 2600 psia.

- The EPU LOCV analysis assumed the same instantaneous termination of FW and steam flow, and the reactor trip on the RPS HPPT at a setpoint of 2415 psia. The peak RCS pressure was 2669 psia.

For Loss of FW (LOFW) –

- The ATWS LOFW analysis assumed instantaneous termination of all feewater flow and delayed reactor trip until the DSS setpoint of 2450 psia was reached.

- The EPU FLB analysis assumed the same instantaneous termination of FW. In addition, the 0.21 ft^2 break depleted the SG inventory more quickly than the LOFW event, forcing degradation in heat transfer and a rapid RCS heat-up. The SG low level trip was ignored and the reactor tripped on RPS HPPT at a setpoint of 2460 psia. The peak RCS pressure was 2715 psia.

EPU LOCV adjustment – The licensee calculated that, if the EPU LOCV trip was delayed from the RPS HHPT to the DSS trip (i.e., delayed from 2415 psia to 2450 psia with an additional 0.85 second response time per Table 1 of FPL letter L-2011-273 (Reference 59)), the peak RCS pressure would increase by approximately 107 psi, from 2669 to 2776 psia. The licensee's calculation was based on the information in licensing report Section 2.8.5.0.6, Table 2.8.5.0-4, "Safety Analysis RSP and ESFAS Setpoints and Delay Times," and licensing report Section 2.8.5.2.1, Table 2.8.5.2.1-2, "Sequence of Events and Transient Results for the LOCV Event," which showed that the HPP trip setpoint of 2415 psia occurred at 16.30 seconds and the PSVs opened at a setpoint of 2575 psia at 18.195 seconds. Based on these data, the rate of pressurization was calculated to be 84 psi/second using the linear approximation approach. For the trip delayed to 2450 psia with 0.85 seconds additional response, the peak pressures was calculated to increase by 107 psi (84 x 0.85 + (2450 -2415)). The estimated peak pressure of 2776 psia is well within the limit of 3214.7 psia (3200 psig).

EPU FLB adjustment – The licensee calculated that, if the EPU FLB trip was changed from the RPS HPPT to the DSS trip (i.e., tripped at 2450 with an additional 0.6 second response per

Table 1 of FPL letter L-2011-273 (Reference 59)), the peak RCS pressure would increase by approximately 43 psi, from 2715 to 2758 psia. The licensee's calculation was based on the information in licensing report Section 2.8.5.0.6, Table 2.8.5.0-4, and licensing report Section 2.8.5.2.4, Table 2.8.5.2.4-2, "Sequence of Events and Transient Results for the Feedwater Line Break," which showed that the HPPT setpoint of 2460 psia occurred at 31.04 seconds and the PSVs opened at a setpoint of 2575 psia at 32.66 seconds. Based on these data, the rate of pressurization was calculated to be 71 psi/second using the linear approximation approach. For the trip remained at 2460 psia (conservative with respective to 2450 psia) with 0.60 seconds additional response, the peak pressures was calculated to increase by 43 psi (71 x 0.60). The estimated peak pressure of 2758 psia is well within the limit of 3214.7 psia.

Based on the EPU LOCV and EPU FLB analyses considering reactor response delay time associated a DSS trip while ignoring the RPS HPPT, the results showed that the DSS trip set at 2450 psia would maintain the peak pressure for the limiting ATWS events well within the ATWS acceptance pressure limit under the EPU conditions.

The analyses of the EPU LOCV and EPU FLB did not credit the reactor trip on turbine trip for reducing the peak RCS pressure. The results of the analyses also showed that the AFW did not impact peak RCS pressure since no AFW flow entered the SGs before the peak RCS pressure occurred. Therefore, the setpoints of the DTT and DAFAS would not affect the peak RCS pressure, and therefore remained valid.

Conclusion

The NRC staff has reviewed the information submitted by the licensee related to ATWS and concluded that the licensee has adequately accounted for the effects of the proposed EPU on ATWS. The NRC staff concludes that the licensee has demonstrated that the DSS will continue to meet the requirements of 10 CFR 50.62 following implementation of the proposed EPU. Additionally, the licensee has demonstrated that the current setpoints of the DSS, DTT and DAFAS are adequate to prevent the peak primary system pressure following an ATWS event from exceeding the acceptance limit. Therefore, the NRC staff concludes the proposed EPU is acceptable with respect to the ATWS event.

2.8.6 Additional Review Areas (Reactor Systems)

2.8.6.1 Loss of Decay Heat Removal at Mid-Loop Operation

As stated in licensing report Section 2.8.7.1.2 (Reference 2), St. Lucie 2 is considered to be in "mid-loop" conditions when the RV water level is below the top of the RCS hot-leg (with the elevation at 31 ft, 3 in) and at or above the mid-plane of the hot-leg piping (with the elevation at 29 ft, 6 in). It also considered in "reduced inventory" conditions when the RV water level is at level beginning 3 feet below the RV flange and continuing down to the top of the hot-leg. (Three feet below the flange corresponds to an elevation of 33 ft, 0 in.) Operating procedures provide limitations during mid-loop or reduced-inventory conditions that minimize the risks associated with a loss of decay heat removal (DHR), ensure the core can remain covered if DHR is lost, and ensure timely containment closure in the event of core boiling.

Loss of DHR during non-power operation and the consequences of such a loss prompted NRC issuance of GL 88-17, "Loss of Decay Heat Removal," which required the implementation of expeditious actions and programmed plant enhancements to address the issue related to the loss of DHR capability during non-power operations. The licensee confirmed in letter dated November 17, 1990 to NRC from D. A. Sager (FPL) (9011270222) that all modifications associated with GL 88-17 commitments have been completed and are operational.

The licensee reviewed the CLB at St. Lucie 2 to determine whether identified actions taken to preclude loss of decay heat removal during non-power operation in response to GL 88-17 were affected by the proposed power uprate. The licensee identified that the following plant parameters would be affected: (1) the minimum required shutdown time prior to reduced inventory or mid-loop operation based on the available RCS vent area; (2) required number of charging pumps as a function of time since shutdown; and (3) containment closure requirements associated with the calculated time to core boil. The licensee performed analyses for a loss of DHR event to determine the values of above parameters applicable to EPU conditions. The analyses considered various initial conditions and assumptions for RCS temperature, RCS heatup volume and boil-off volume, operating cycle length, and time since shutdown. The values of input parameters and assumptions were listed in licensing report Tables 2.8.7.1-1 and 2.8.7.1-2, respectively. The proposed power uprate of 3020 MWt was used in the analyses. Results of the analyses were listed in licensing report Table 2.8.7.1-3 and discussed in item 5 of licensing report Section 2.8.7.1.3. The NRC staff found that: (1) the scope of the analyses was consistent with the current loss of DHR analysis, and (2) applicable assumptions for decay heat and time to boil, and key input parameters including RCS heatup volume, RCS boil-off volume and the maximum RV pressure to avoid core uncover, remained the same as that used in the current analysis. Also, the licensee stated that the results of the analyses would be incorporated into St. Lucie 2 plant procedures, which would ensure that the core could remain covered if the DHR system were lost, and ensure timely containment closure in the event of core boiling. Therefore, the NRC staff determined that the analyses of a loss of DHR event for EPU conditions were acceptable. .

Based on its review, the NRC staff found that (1) multiple, redundant backup systems are available to mitigate a loss of DHR, and (2) the licensee has adequately addressed the increased decay heat generation for EPU as it affects calculations supporting mid-loop and reduced inventory operations. Therefore, the NRC staff concluded that the licensee's evaluation of the effect of the power uprate on the loss of DHR was acceptable.

2.8.6.2 Natural Circulation Cooldown

licensing report Section 2.8.7.2 and the response to RAI SRXB-77 (References 11; 60) document licensee's evaluation of the impact of its requested power uprate on the capability of the plant to cool down via natural circulation.

The licensee performed a natural circulation cooldown (NCC) analysis for EPU conditions by using the CENTS computer code, documented in WCAP-15996-P-A, Revision 1 (ADAMS Accession Nos. ML053320045, ML053320046, ML053320115, and ML053320141 for the proprietary version, and ML053290349, ML053320174, ML053320180, and ML0533200182 for the non-proprietary version), to simulate plant response to a LOOP followed by an NCC. In the original response to RAI SRXB-77 of FPL letter L-2011-532 (Reference 11), the licensee indicated that the temperature and pressure conditions considered in the NCC analysis were within the acceptable range of the CENTS code, and the RCS was kept above the saturation pressure corresponding to the RV upper head temperature. These results provided reasonable assurance that no two-phase flow conditions were present during the NCC analysis.

The NCC analysis was performed using only safety grade equipment and assuming the worst single failure, loss of one emergency power train. Specifically, of the four total safety grade atmospheric dump valves, only two were used (one per SG because of consideration of the worst single failure, a loss of one emergency power train, which would disable one train of components associated with ADVs, CVCS, AFW system and SDC system. Credit of only safety grade equipment and consideration of the worst single failure in the NCC analysis was consistent with Paragraphs B.1.A and B.1.C of BTP 5.4 in SRP Chapter 5, Revision 3, and therefore, was acceptable.

The analysis initiated from EPU conditions to SDC entry conditions. It assumed following a LOOP, the plant was maintained at hot standby conditions for 4 hours before entering the coodown. This assumption would increase in the cooldown time and thus, result in greater required AFW in the CST for plant cooldown. This assumption was consistent with Paragraph B.7, "Auxiliary Feedwater Supply," of the BTP 5.4, and therefore, was acceptable.

The decay heat rates were based on ANSI/ANS-5.1-1979 including uncertainties. The licensee indicated (RAI SRXB-77 response (Reference 11)) that the decay heat rates would bound fuel designs with up to (1) 5 weight percent fuel enrichment, (2) fuel burnups to 73 GWd/MTU and (3) operating cycles up to 24 months in duration. Therefore, the NRC staff agreed with the licensee that the decay heat rates used in the NCC analysis would bound the fuel designs and operating cycle lengths anticipated as part of the St. Lucie 2 EPU application and were acceptable. As for the AFW enthalpy, the licensee used the maximum value corresponding to maximum CST temperature. This assumption was conservative, maximizing the required water in the CST, and was acceptable.

The licensee performed the NCC analysis for two separate cases assuming cooldown rates of 30°F/hour and 50°F/hour. After 4 hours at hot standby conditions, the operators would cool the plant down to the SDC entry conditions at the specified cooldown rate of either 30°F/hour or 50°F/hour. The limiting case analyzed demonstrated that the plant could be cooled down to SDC entry conditions using the same equipment as the existing analysis of record while maintaining pressure control for a LOOP event. Specifically, the results showed in licensing report Table 2.8.7.2-2 that the maximum total AFW flow from the CST to achieve NCC conditions was 178,200 gallons, which is within the required lower limit of 307,000 gallons specified in TS LCO 3.7.1.3.

NCC Reanalysis

BTP 5-4 of SRP Chapter 5 provided guidance for the NCC analysis. Specifically, its Paragraphs B.6 and B.7 (Revision 3) indicated that the information of plant procedures should be considered in the NCC analysis and the AFW supply for cooldown should be based on the longest cooldown time needed to maximize the required AFW supply for cooldown conditions with or without a LOOP considering effects of a single failure. During the review, the NRC staff requested the licensee to address its compliance with the B.6 and B.7 guidance. In response, the licensee provided additional information and results of the NCC reanalysis in FPL letter L-2012-157 (Reference 60). The licensee indicated that while performing cases runs to confirm the consistency of the NCC analysis with St. Lucie 2 procedures, it found that a feature of the CENTS code had been unintentionally activated. The use of the modeling feature resulted in a non-conservative conclusion for the NCC analysis. This finding led the licensee to perform a NCC reanalysis. The reanalysis was conducted with the non-conservative model feature disabled, using the CENTS code in a configuration consistent with the previously NRC-approved version (ADAMS Accession No. ML032790634). In the reanalysis, changes were made to the sequence of operator actions applied during the simulated NCC transient. These changes were necessary as a direct consequence of disabling the affected modeling feature, which influenced the T-H response of the NCC transient. The operator actions were credited in the reanalysis to control cooldown rates at various points during the event in order to ensure that there was no void in the RV upper head (RVUH) while simultaneously maintaining the plant within appropriate operational limits. Specifically, these operator actions included holding periods and reductions in cooldown and depressurization rates, up to and including a soak period. The licensee confirmed that (1) the operator actions performed in the reanalysis were consistent with the limitations in the current plant specific NCC procedures, and (2) they were performed using only safety grade equipment that would be operable from the control room, assuming the LOOP with a limiting single failure of a loss one emergency power train. The soak time included in the current St. Lucie 2 NCC procedures would be updated as part of the EPU implementation process based on the EPU NCC reanalysis.

The licensee performed the EPU NCC reanalysis for two separate cases assuming cooldown rates of 30 °F/hour and 50 °F/hour. After 4 hours at hot standby conditions, the operators would cool the plant down to the SDC entry conditions at the specified cooldown rate of either 30 °F/hour or 50 °F/hour. The results were provided in Table 1 of Attachment 1 to FPL letter L-2012-157 (Reference 60), which would be used to supersede those listed in licensing report Table 2.8.7.2-2. The results of the reanalysis for the limiting case showed that the plant could be cooled down to SDC entry conditions using the same equipment as the existing analysis of record while maintaining pressure control for a LOOP event. Specifically, the results showed that:

1. The maximum core ΔT during the 30 °F/hour and 50 °F/hour cooldown was less than the normal full power ΔT of 53 °F. The result would ensure adequate RCS cooldown and provide reasonable assurance that thermal stresses would not be of concern.

2. The ADVs at the EPU conditions were adequately to achieve cooldown to the SDC entry point in approximately less than 24 hours at a cooldown rate of either 30 °F/hour or 50 °F/hour.

3. The maximum total AFW flow from the condensate storage tank CST to achieve NCC conditions was 281,000 gallons, which is bounded by a CST usable volume value of 293,567 gallons. The usable volume is equivalent to the required lower limit of 307,000 gallons specified in TS LCO 3.7.1.3 for the CST minus the unusable volume of 13,433 gallons consistent with EPU licensing report Table 2.5.4.5-1.

This result ensured that adequate CST supply would be available to cooldown the plant to the SDC entry condition during NCC conditions. The result satisfactorily met the guidance in Paragraph B.7 of BTP 5.4 in SRP Chapter 5 (Revision 3).

The NRC staff found that (1) the analysis used the CENTS code in a configuration consistent with the previously NRC-approved version and credited for consequence mitigation only the safety grade equipment with consideration of the worst single failure safety, (2) the values of initial conditions and assumptions used in the analysis were conservative, resulting in longest cooldown time and a greatest amount of AFW for the cooldown, and (3) the results showed that adequate water in the CST was available to cool the plant from the hot standby to the SDC entry conditions within a reasonable period of time without voiding in the RCS. Therefore, the NRC staff determined that the NCC analysis was acceptable for supporting the EPU application.

2.8.6.3 Boron Precipitation

Regulatory Evaluation

The staff evaluation of the St Lucie 2 ECCS performance consisted of reviewing the results of the post-LOCA long-term cooling analyses at 3030 MWt. This analysis was reviewed to show that the plant EOPs can properly mitigate the boric acid accumulation in the RCS following both LBLOCAs and SBLOCAs. The EOPs specify the latest time at which simultaneous hot and cold leg injection must be initiated to prevent further build up and boric acid precipitation following all LOCAs.

The NRC staff evaluation included an audit of the Westinghouse calculations for analyses pertaining to boric acid precipitation analyses and timing for the switch to hot leg injection. The licensee employed the NRC-approved CENPD-254 post-LOCA long-term cooling evaluation model.

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

Technical Evaluation

Small Break Behavior

The licensee has provided an assessment of post-SBLOCA long-term cooling. The assessment covers the full spectrum of break sizes, from the double-ended guillotine break down to and including the 0.005 ft^2 cold leg break in the reactor coolant discharge leg. Control of boric acid precipitation for SBLOCAs has also been demonstrated. Of particular importance is the EOP action to initiate a cooldown for small breaks no later than one hour post-LOCA. This will ensure small breaks, which may not allow sufficient hot and cold leg injection to establish a flushing flow, will refill with injection and re-establish single phase natural circulation that will remove the boric acid built up during the early portion of the SBLOCA. Single phase natural circulation disperses the boric acid built up in core throughout the primary system, thereby reducing the boric acid concentration well below precipitation limits following all small breaks. The staff finds the procedures and analysis of intermediate and SBLOCA boric acid control acceptable.

Large Break Behavior

The limiting break location for assessments of boric acid precipitation is the discharge of the RCP in the cold leg. The staff audit calculations of large breaks confirm that precipitation is precluded with a boric acid concentration of 27.5 weight percent at 8.5 hours when simultaneous injection is initiated at no later than 6 hours post-LOCA. The licensee calculated a maximum acid concentration in the core of 29.1 weight percent at 9.9 hours. Note that the staff performed calculations modeling the flushing flow to confirm the maximum calculated concentration when simultaneous injection is imitated. The precipitation limit for Unit 2 was chosen to be 29.27 weight percent based on the minimum containment pressure of 14.7 psia.

The licensee also confirmed that the temperature of the lower plenum at about 2 hours post-LOCA, when the mixing from the core to the lower plenum begins, is greater than 140 °F. Staff calculations showed that the concentration in the core was about 12.5 weight percent suggesting that the temperature must be greater than 140 °F to preclude precipitation in the lower plenum.

The major assumptions in the boric acid precipitation analysis are:

Core power	2652 Mwt (plus uncertainty)
Decay heat standard	1971 ANS decay heat standard (1.2 mltiplier)
Mixing volume	50% lower plenum, core, and upper plenum below top of hot leg elevation
Concentration of RWST	2300 ppm
Limiting axial power shape	bottom peaked axial power distribution
Hot leg injection flow	250 gpm
Limiting break location	cold leg at RCP discharge

Hot and cold leg injection is required to be aligned at 4 to 6 hours post-LOCA, but no later than 6 hours. The Unit 2 hot-leg injection is 250 gpm, which matches boiloff at 6 hrs. Thus flushing will increase immediately after the switch to simultaneous injection for Unit 2. As such, the maximum boric acid concentration in the core remains at 26.26 weight percent.

While the maximum concentration is very near the precipitation limits it is important to note the conservatism inherent in these analyses. The minimum containment pressure is about 25 psia. Containment calculations show the minimum containment pressure to be greater than 25 psia at 6 hours into the event. This demonstrates that the core pressure is about 30 psia, producing a precipitation limit greater than 35 weight percent. A summary of the additional conservatisms in the St Lucie 2 long-term cooling analyses are:

- Saturated fluid enters the core to minimize precipitation timing
- Loop frictional and geometric losses increased by 10 percent inside the RV and 20 percent in the loops
- Vapor exiting the core contains no boric acid
- Entrainment of liquid from the core is neglected
- Hot leg injection maximum flow rate was reduced by 75 percent
- Maximum boric acid concentrations for all sources were assumed with a 100 ppm uncertainty added.
- The boric acid makeup tanks were assumed to completely discharge into the RV

The staff model includes the impact of the loop resistance on the mixing volume, which slowly increases with time. The loop resistance included a locked rotor K-factor for the RCPs. The void distribution was determined using a drift-flux methodology to model the axial gradient in void in the core region. The staff drift flux model has been validated against separate effects two-phase level swell and bundle uncover and heat-up test data (GE level swell, THTF, G-2 level swell and uncovery data, Achilles level swell data, and THETIS void data). The staff model also assumes the break is located on the top of the discharge leg so that the loop seals completely fill with liquid. This increases the loop resistance and retards the growth of the mixing volume during the event and causes earlier precipitation limits to be reached.

The staff also notes that entrainment of the hot-side injection would not occur prior to the initiation of simultaneous injection at 4 hours. Both the Wallis-Steen and the Ishii-Grolmes correlations support this conclusion. Based on these calculations, hot and cold-side injection is not initiated during the period of time entrainment could preclude injection into the hot legs. The staff finds this analysis to be acceptable since the earliest switch time is 4 hours following opening of the break.

Since the switch to simultaneous injection is a key operator action to assure boric acid buildup is precluded, the licensee also confirmed that the operators would be tested annually to ensure that the operator action timing of no later than 6 hours post-LOCA for realignment of HPSI would be maintained and verified as part of the operator qualification and training program.

Conclusion

A review of the boric acid precipitation analyses performed for St Lucie 2 demonstrates acceptable ECCS performance. Evaluation of boric acid precipitation timing for all break sizes demonstrates that prevention of precipitation is also ensured and the EOPs reflect the analysis timing for operator action to align the ECCS for hot-side injection to preclude the precipitation. Based on these results, the staff finds that, for St. Lucie 2 at the power level of 3030 MWt (including uncertainty), acceptable ECCS performance is ensured for all break sizes and locations where control of boric acid is required for compliance with the requirements set forth in 10 CFR 50.46 and 10 CFR Part 50, Appendix K.

2.8.6.4 EPU Methods Implementation

As discussed in Section 2.8.5.0.9 of the licensing report (Reference 2), the licensee performed non-LOCA analyses with the following computer codes:

1. TWINKLE and FACTRAN

TWINKLE is a multi-dimensional spatial neutronics code which uses an implicit finite-difference method to solve the two group transient neutronics equations in one, two, and three dimensions. This code is documented in the NRC-approved Topical Report, WCAP-7979-P-A (ADAMS Accession No. ML080650324).

FACTRAN is a radial pellet/clad temperature calculation model which is used to calculate the transient heat flux at the surface of a rod. This code is documented in the NRC-approved Topical Report WCAP-7908-P-A (ADAMS Accession No. ML080630436).

The licensee used TWINKLE and FACTRAN for St. Lucie 2 EPU analysis of the uncontrolled CEA withdrawal from a subcritical condition event and the CEA ejection event. Also, both codes were used in the current AOR for St. Lucie 2.

2. RETRAN

RETRAN simulates a multi-loop system using a model containing a RV, hot- and cold-leg piping, SGs, and pressurizer. The code also includes point kinetics and reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the SG uses a detailed nodalization for thermal transients. This code is documented in the NRC-approved Topical Report, WCAP-14882-P-A (ADAMS Accession No. ML093421329). The RETRAN code was also used in the current AOR for St. Lucie 2.

3. VIPRE with the ABB-NV and W-3 Critical Heat Flux (CHF) Correlations

The VIPRE code is used to perform core T-H analyses, determining coolant density, mass velocity, enthalpy, vapor void, static pressure and the DNBR distribution along parallel flow channels within the reactor core under normal operational and transient conditions. The VIPRE code is documented in the NRC-approved Topical Report, WCAP-14565-P-A (ADAMS Accession No. ML993160153) and the associated Addendum 1 (ADAMS Accession No. ML040700915). The licensee uses the ABB-NV and W-3 critical heat flux (CHF) correlations to calculate DNBRs. The safety DNBR limits have been imposed to assure that there is at least a 95 percent probability at a 95 percent confidence level that the hot rods in the core do not experience a DNB during a transient. For CE 16x16 fuel assemblies in the St. Lucie 2 reactor core, the licensee uses the VIPRE code and the ABB-NV correlation with a correlation limit of 1.13 for the DNBR analysis. The VIPRE code, and CHF correlations and associated safety limits were used in both the current AOR and EPU analysis for St. Lucie 2.

4. Advanced Nodal Code (ANC)

ANC is an advanced nodal code used for two-dimensional and three-dimensional neutronic calculations. It calculates power distributions, peaking factors, critical boron concentrations, control rod worths, and reactivity coefficients. This code is documented in the NRC-approved Topical Report WCAP-10965-P-A (ADAMS Accession No. ML080630392). ANC was used in the current AOR and EPU analysis for St. Lucie 2.

Since all the above computer codes are the NRC-approved codes and are used in the current AOR for St. Lucie 2, and the use of the codes complies with the applicable conditions specified in the SEs approving topical reports, the NRC staff determined that the use of the codes were acceptable for the St. Lucie 2 EPU analysis. The evaluation of the licensee's compliance with the SE conditions is discussed in the sections 2.8.6.4.1 through 2.8.6.4.3 as follows.

2.8.6.4.1 FACTRAN

FACTRAN, described in WCAP 7908-A (ADAMS Accession No. ML080630436), is a radial pellet/clad temperature calculation model which is used to calculate the transient heat flux at the surface of a rod. In its SER approving WCAP-7908, the NRC staff imposed several conditions for the use of FACTRAN. When applying to the St. Lucie 2 EPU analysis, the licensee addressed its compliance with the conditions in Table A.6-1 Appendix A of the licensing report (Reference 2). The NRC staff has reviewed the licensee's description of compliance and discusses the evaluation as follows.

Condition (1) - The fuel volume-averaged temperature or surface temperature can be chosen at a desired value which includes conservatisms reviewed and approved by the NRC.

Evaluation - The licensee indicated that the FACTRAN code was used in the analyses of the following transients for St. Lucie 2: uncontrolled rod withdrawal from subcritical and CEA ejection. In the analysis, initial fuel temperatures used as FACTRAN input were calculated using the NRC-approved FATES3B computer code, as described in CENPD-139-P-A (ADAMS Accession No. ML120960147), "Fuel Evaluation Model Topical Report", CEN-161(B)-P-A (ADAMS Accession No. ML120960155), and CEN-161(B)-P-SUPPL1-P-A (ADAMS Accession No. ML120960175), "Improvements to Fuel Evaluation Model". Since the NRC-approved methods were used to calculate uncertainties for fuel temperatures, the NRC staff determined that the calculated fuel temperatures satisfied Condition (1) and were acceptable.

Condition (2) - Table 2 presents the guidelines used to select initial temperatures.

Evaluation - Table 2 of the SER specifies that the initial fuel temperatures assumed in the FACTRAN analyses of the following transients should be "High" and include uncertainties: loss of flow, locked rotor, and CEA ejection. As discussed in the above evaluation on Condition (1) response, fuel temperatures were used as input to the FACTRAN code in the CEA ejection analysis for St. Lucie 2. Since the fuel temperatures, which were calculated using the FATES3B computer code, documented in CENPD-139-P-A, included uncertainties and were conservatively high. Therefore, the NRC staff determined that Condition (2) was satisfied. The licensee clarified that FACTRAN was not used in the loss of flow and locked rotor analyses.

Condition (3) - The gap heat transfer coefficient may be held at the initial constant value or can be varied as a function of time as specified in the input.

Evaluation - The licensee indicated that the gap heat transfer coefficients applied in the FACTRAN analyses were consistent with SER Table 2. For the analysis of the rod withdrawal from subcritical event, the gap heat transfer coefficient was kept at a conservative constant value throughout the transient: a high constant value was used to maximize the peak heat flux (addressing DNB concerns) and a low constant value was used to maximize fuel temperatures. For the CEA ejection event transient, the initial gap heat transfer coefficient was based on the predicted initial fuel surface temperature, and was ramped rapidly to a very high value at the beginning of the event to simulate clad collapse onto the fuel pellet. The NRC staff found that the gap heat transfer coefficients used in the applicable analysis were consistent with SER Table 2 and conservative, resulting in a lower DNBR, higher peak fuel temperature, or an earlier clad collapse. Therefore, the NRC staff determined that the gap heat transfers confidents used in that analysis were acceptable and Condition (3) was satisfactorily addressed.

Condition (4) - …the Bishop-Sandberg-Tong correlation is sufficiently conservative and can be used in the FACTRAN code. It should be cautioned that since these correlations are applicable for local conditions only, it is necessary to use input to the FACTRAN code which reflects the local conditions. If the input values reflecting average conditions are used, there must be sufficient conservatism in the input values to make the overall method conservative."

Evaluation - The licensee confirmed that local conditions related to temperature, heat flux, peaking factors and channel information were input to FACTRAN for analyzing the uncontrolled rod withdrawal from subcritical and CEA ejection event in support of St. Lucie 2 licensing applications. Therefore, NRC staff agreed with the licensee that additional justification was not needed.

Condition (5) - The fuel rod is divided into a number of concentric rings. The maximum number of rings used to represent the fuel is 10. Based on our audit calculations we require that the minimum of 6 should be used in the analyses.

Evaluation - The licensee confirmed that at least 6 concentric rings were assumed in FACTRAN for analyzing the uncontrolled rod withdrawal from subcritical and CEA ejection event in support of St. Lucie 2 licensing applications. The NRC staff determined that the licensee's use of the number for concentric rings met the Condition (5), and additional justification was not needed.

Condition (6) - Although time-independent mechanical behaviors (e.g., thermal expansion, elastic deformation) of the cladding are considered in FACTRAN, time-dependent mechanical behavior (e.g., plastic deformation) is not considered in the code, for those events in which the FACTRAN code is applied (see Table 1), significant time-dependent deformation of the cladding is not expected to occur due to the short duration of these events or low cladding temperatures involved (where DNBR Limits apply), or the gap heat transfer coefficient is adjusted to a high value to simulate clad collapse onto the fuel pellet.

Evaluation - The licensee indicated that for St. Lucie 2, FACTRAN was used in the analysis of the uncontrolled rod withdrawal from subcritical and CEA ejection events, which were included in the list of events provided in Table 1 of the SER. Table 1 of the SER lists the FACTRAN events for which time-dependent deformation of the cladding is not expected to occur. For the uncontrolled rod withdrawal from subcritical event, relatively low cladding temperatures were involved. For the CEA ejection event, a high gap heat transfer coefficient was applied to simulate clad collapse onto the fuel pellet. Both events were short in duration and the gap heat transfer coefficients applied in FACTRAN were consistent with SER Table 2. Therefore, the NRC staff determined that Condition (6) was satisfactorily addressed.

Condition (7) - The one group diffusion theory model in the FACTRAN code slightly overestimates at BOL and underestimates at EOL the magnitude of flux depression in the fuel when compared to the LASER code predictions for the same fuel enrichment. The LASER code uses transport theory. There is a difference of about 3 percent in the flux depression calculated using these two codes. When [T(centerline) – T(surface)] is on the order of 3000 °F, which can occur at the hot spot, the difference between the two codes will give an error of 100 °F. When the fuel surface temperature is fixed, this will result in a 100 °F lower prediction of the centerline temperature in FACTRAN. We have indicated this apparent non-conservatism to Westinghouse. In the letter NS-TMA-2026, dated January 12, 1979, Westinghouse proposed to incorporate the LASER-calculated power distribution shapes in FACTRAN to eliminate this non-conservatism. We find the use of the LASER-calculated power distribution in the FACTRAN code acceptable.

Evaluation - The licensee indicated that the condition of concern (T(centerline) – T(surface) is on the order of 3000 °F) was expected for events that would reach, or come close to, the fuel melt temperature. As this would be applicable only to the CEA ejection event, the licensee stated that LASER- calculated power distributions were used in the FACTRAN analysis of the CEA ejection transient for St. Lucie 2. Based on the licensee's statement, the NRC staff determined that Condition (7) was met.

2.8.6.4.2 RETRAN

RETRAN is a flexible, general purpose, thermal/hydraulic computer code that is used to evaluate the effect of various upset reactor conditions on the RCS. The code includes point kinetics and reactivity effects of moderator, fuel, boron, and control rods. The secondary side of the SG uses detailed nodalization for the thermal transients. The NRC-approved version of the RETRAN code is described in WCAP-14882-P-A (ADAMS Accession No. ML093421329).

In its approval of the RETRAN code, the NRC staff imposed three conditions regarding its application to Westinghouse PWRs. The licensee discussed its compliance with the conditions in Table A.7-1 of the licensing report. The NRC has reviewed the licensee's description of compliance and discusses the evaluation as follows:

Condition (1) - The transients and accidents that Westinghouse proposes to analyze with RETRAN are listed in the NRC staff's SER of RETRAN, and the NRC staff review of RETRAN usage by Westinghouse was limited to this set. Use of the code for other analytical purposes will require additional justification.

Evaluation - The staff has reviewed the RETRAN-analyzed transients listed by the licensee in Table A.7-1 of licensing report and found that the transients, except for the "break in instrument line or other lines from the RCPB that penetrate the containment" and the "asymmetric steam generator transients (ASGTs)," were all included in the list of events evaluated by the NRC staff as documented in its SER approving WCAP-14882-P-A.

The licensee analyzed the break in instrument line or other lines from the RCPB that penetrate the containment (or primary line break event) to provide mass release input to the analyses of radiological consequences. The limiting primary line break event previously identified in the AOR for St. Lucie 2 was a letdown line break. As for the ASGTs, the limiting event previously identified in the St. Lucie 2 AOR was the sudden closure of a MSIV (loss of load to one SG). Since the licensee confirmed that (1) the T-H response of the letdown line break was within the range for events analyzed with RETRAN, such as the SG tube rupture event, and (2) the T-H response of the ASGT event was within the range for events analyzed with RETRAN, such as the loss of condenser, loss of load, or steam line break events, the NRC staff concluded that the use of RETRAN to analyze the primary line break and ASGT events was acceptable.

Condition (2) - WCAP-14882 describes modeling of Westinghouse designed 4-, 3-, and 2-loop plants of the type that are currently operating. Use of the code to analyze other designs, including the Westinghouse AP600, will require additional justification.

Evaluation - St. Lucie 2 consists of a 2x4 loop CEdesigned unit which currently uses RETRAN to perform the analyses of non-LOCA events. The NRC staff found that the NRC-approval of use of RETRAN for St. Lucie 2 was included in Reference A.7-1 of an SER dated January 31, 2005 (ADAMS Accession No. ML050120363), and therefore, concluded that no further justification was needed.

Conditions (3) - Conservative safety analyses using RETRAN are dependent on the selection of conservative input. Acceptable methodology for developing plant-specific input is discussed in WCAP-14882, and in the Westinghouse Reload Safety Evaluation Methodology. Licensing applications using RETRAN should include the source of and justification for the input data used in the analysis.

Evaluation - The licensee stated that assurance that the RETRAN input data is conservative for St. Lucie 2 was provided via Westinghouse's use of transient-specific analysis guidance documents, which provided the basis for collection of conservative plant-specific input values from responsible St. Lucie 2 and Westinghouse sources. Consistent with the Westinghouse Reload Evaluation Methodology documented in WCAP-9272-P-A (8508060215), the safety analysis input values used in the St. Lucie 2 analyses were selected to bound conservatively the values expected in subsequent operating cycles. In consideration of the licensee's statement, the staff was reasonably assured that conservative input was selected for the St. Lucie 2 EPU.

2.8.6.4.3 VIPRE

VIPRE is a sub-channel T-H code used to evaluate local conditions for departure from nuclear boiling analysis, the Westinghouse methodology for which is described in WCAP-14565-P-A (ADAMS Accession No. ML993160153).

In its generic approval of the VIPRE code, the NRC staff issued four conditions to the VIPRE method. When applying to St. Lucie 2 EPU analysis, the licensee addressed its compliance with the conditions in Table A.8-1 of the licensing report. The NRC staff has reviewed the licensee's description of compliance and discusses the evaluation as follows.

Condition (1) - Selection of the appropriate CHF correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters for a specific plant application should be justified with each submittal.

Evaluation – The licensee stated that the safety DNBR limits have been imposed to assure that there is at least a 95 percent probability at a 95 percent confidence level that the hot rods in the core do not experience a DNB during a transient. For CE 16x16 fuel assemblies in the St. Lucie 2 reactor core, the licensee used the VIPRE code and the ABB-NV correlation with a correlation limit of 1.13 for the DNB analysis. The NRC staff found that the use of the ABB-NV DNB correlation and the plant specific hot channel factors and other fuel dependent parameters in the St. Lucie 2 DNB analysis was based on the same methodologies as that used to support the Westinghouse reload methodology and implement 30 percent SG tube plugging limit for St. Lucie 2 approved previously by the NRC (licensing report Reference A.8-1, ADAMS Accession No. ML050120363). Therefore, the NRC staff determines that that the plant-specific fuel system design parameters proposed for the St. Lucie 2 uprate are justified, and that Condition (1) is satisfied.

Condition (2) - Reactor core boundary conditions determined using other computer codes are generally input into VIPRE for reactor transient analyses. These inputs include core inlet coolant flow and enthalpy, core average power, power shape and nuclear peaking factors. These inputs should be justified as conservative for each use of VIPRE.

Evaluation - The licensee stated that the core boundary conditions for the VIPRE calculations for the St. Lucie 2 CE 16x16 fuels were all generated from NRC-approved codes and analysis methodologies, and that conservative reactor core boundary conditions were justified for use as input to VIPRE. These boundary conditions were reviewed for each transient individually for the power uprate, as discussed in the various subsections of Section 2.8.5 of this SER. The licensee would verify the conservatism and applicability of the boundary conditions for each reload as a part of the licensee's NRC-approved reload method. The staff found that the licensee's use of NRC-approved codes and methodologies would provide acceptable input parameters, and that the cycle-specific confirmation of the parameters adequately would justify their use. The NRC staff, therefore, concluded that Condition (2) was satisfied.

Condition (3) - The NRC staff's generic SER for VIPRE set requirements for use of new CHF correlations with VIPRE. Westinghouse has met these requirements for using the WRB-1, WRB-2, and WRB-2M correlations. The DNBR limit for WRB-1 and WRB-2 is 1.17. The WRB-2M correlation has a DNBR limit of 1.14. Use of other CHF correlations not currently included in VIPRE will require additional justification.

Evaluation - As discussed in response to Condition (1), the ABB-NV correlation with a limit of 1.13 was used in the DNB analysis of CE 16x16 fuels for St. Lucie 2. For reactor system conditions outside the range of the ABB-NV correlations, the licensee would use the W-3 correlation with a DNBR limit of 1.3 to W-3 predictions above 1000 psia and a DNBR limit of 1.45 to W-3 predictions below 1000 psia. The NRC staff found that the use of the DNBR correlations and the associated safety limits was based on the same methodologies as that used to support the Westinghouse reload methodology and implement 30 percent SG tube plugging limit for St. Lucie 2 approved previously by the NRC (Reference A.8-1, ADAMS Accession No. ML050120363). Therefore, the NRC staff determined that the use of the DNB correlations and associated DNBR limits in the DNB analysis supporting the St. Lucie 2 EPU was justified, and that Condition (3) was satisfied.

Condition (4) - Westinghouse proposes to use the VIPRE code to evaluate fuel performance following postulated design-basis accidents, including beyond-CHF heat transfer conditions. These evaluations are necessary to determine the extent of core damage and to ensure that the core maintains a coolable geometry in the evaluation of certain accident scenarios. The NRC staff's generic review of VIPRE did not extend to post CHF calculations. VIPRE does not model the time dependent physical changes that may occur within the fuel rods at elevated temperatures. Westinghouse proposes to use conservative input in order to account for these effects. The NRC staff requires that appropriate justification be submitted with each usage of VIPRE in the post-CHF region to ensure that conservative results are obtained.

Evaluation - The licensee used VIPRE to model post-CHF fuel performance in one transient sequence: the locked rotor event. The licensee confirmed that VIPRE modeling of the fuel rod was consistent with the model described in the NRC-approved report, WCAP-14565-P-A (ADAMS Accession No. ML993160153) documenting the VIPRE models. The licensee also listed the conservative assumptions employed in the VIPRE fuel rod modeling. These assumptions included the following:

1. DNB was assumed to occur at the beginning of the transient.
2. Film boiling was calculated using the Bishop-Sandberg-Tong (BST) correlation.
3. The Baker-Just correlation accounted for heat generation in fuel cladding due to zirconium water reaction.
4. Fuel rod input was based on the maximum fuel temperature at the given power.
5. The hot spot power factor was equal to or greater than the design linear heat rate. Uncertainties were applied to the initial operating conditions in the limiting direction.

Since the use of VIPRE was consistent with NRC-approved report, WCAP-14565-P-A, and additional conservative assumptions were included in the VIPRE fuel rod modeling, the NRC staff determined the limited post-CHF modeling in VIPRE was acceptable and that Condition (4) was satisfied.

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with EPUs to ensure the adequacy of the sources of radioactivity used by the licensee as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes. The 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) concentrations of all radionuclides other than fission products in the reactor coolant, (4) leakage rates and associated fluid activity of all potentially radioactive water and steam systems, and (5) potential sources of radioactive materials in effluents that are not considered in the St. Lucie 1 FSAR related to liquid waste management systems and GWMSs. The NRC's acceptance criteria for source terms are based on (1) 10 CFR Part 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas; (2) 10 CFR Part 50, Appendix I, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the ALARA criterion; and (3) GDC 60, insofar as it requires that the plant design includes means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 11.1.

Technical Evaluation

The core isotopic inventory is a function of the core power level, while the reactor coolant isotopic activity concentration is a function of the core power level, the migration of radionuclides from the fuel, radioactive decay and the removal of radioactive material by coolant purification systems. Radiation sources in the reactor coolant include activation products, activated corrosion products and fission products. During reactor operation, some stable isotopes in the coolant passing through the core become radioactive (activated) as a result of nuclear reactions. For example, the non-radioactive isotope oxygen-16 (O-16) is activated to become radioactive nitrogen-16 (N-16) by a neutron-proton reaction as it passes through the neutron-rich core at power. The increase in the activation of the water in the core region is in approximate proportion to the increase in thermal power.

The licensee stated, in Section 2.10.1, Occupational and Public Radiation Doses of the St. Lucie 2 EPU licensing report, that there will be no changes, as a result of the EPU, to the existing gaseous and liquid radioactive waste systems design, plant operating procedures or waste inputs as defined by NUREG-0017, Revision 1. Therefore, a comparison of releases can be made based on current vs. EPU inventories and radioactivity concentrations in the reactor coolant, secondary coolant, and steam. As a result, the licensee states that the impact of the EPU on radwaste releases and Appendix I doses can be estimated using scaling techniques.

The licensee used scaling techniques, based on NUREG-0017, Revision 1 methodology, to assess the impact of EPU on radioactive gaseous and liquid effluents at St. Lucie 2. Use of the adjustment factors presented in NUREG-0017, Revision 1 allows development of coolant activity scaling factors to address EPU conditions.

The licensee's EPU analysis used the plant core power operating history during the years 2003 to 2007, the reported gaseous and liquid effluent and off-site dose calculation data during that period, NUREG-0017, Revision 1, equations and assumptions, and conservative methodology to estimate the impact of operation at the analyzed EPU core power level. The results were then compared to the comparable data from current operation on radioactive gaseous and liquid effluents and the calculated off-site doses from normal operation.

Conclusion

The NRC staff has reviewed the radioactive source term associated with the proposed EPU and concludes that the proposed parameters and resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. The 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 EPU acceptable with respect to source terms.

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

Regulatory Evaluation

The licensee reviewed the following DBA radiological consequences analyses to determine the impact of the EPU:

- LOCA
- FHA
- MSLB
- SGTR
- RCP shaft seizure (locked rotor)
- CEA ejection
- FWLB
- Letdown Line Rupture

The licensee's review for each accident analysis included (1) the sequence of events; (2) models, assumptions, and values of parameter inputs used for the calculation of the total effective dose equivalent (TEDE).

The acceptance criteria for radiological consequences analyses using an alternate source term are based on:

- 10 CFR 50.67, insofar as it describes reference values for radiological consequences of a postulated maximum hypothetical accident;

- RG 1.183, insofar as it describes accident specific dose guidelines for events with a higher probability of occurrence; and

- GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, as defined in 10 CFR 50.2, for the duration of the accident.

Specific review criteria are contained in SRP Section 15.0.1, and guidance from Matrix 9 of RS-001.

Technical Evaluation

To determine the effect of the EPU on the design basis radiological analyses, the licensee reanalyzed the following accidents: LOCA, FHA, SGTR accident, MSLB accident, locked rotor accident, CEA ejection accident, FWLB and the Letdown Line Rupture event. The licensee performed radiological consequence analyses for the various accidents using input assumptions consistent the proposed EPU conditions. As appropriate, the licensee determined the TEDE at the EAB for the limiting 2-hour period, at the LPZ outer boundary for the duration of the accident, and in the control room for 30 days.

The dose consequence analyses were performed by the licensee using the RADTRAD - Numerical Applications, Inc. (NAI) computer code. RADTRAD-NAI estimates the radiological doses at offsite locations and in the control room of nuclear power plants as consequences of postulated accidents. The code considers the timing, physical form and chemical species of the radioactive material released into the environment.

RADTRAD-NAI was developed from the "RADTRAD: Simplified Model for RADionuclide Transport and Removal And Dose Estimation," computer code. NRC sponsored the development of the RADTRAD radiological consequence computer code, as described in NUREG/CR-6604. The RADTRAD code was developed by Sandia National Laboratories for the NRC. The code estimates transport and removal of radionuclides and radiological consequence doses at selected receptors. The NRC staff uses the RADTRAD computer code to perform independent confirmatory dose evaluations as necessary to ensure a thorough understanding of the licensee's methods. The results of the evaluations performed by the licensee, as well as the applicable dose acceptance criteria from RG 1.183, are shown in Table 1 of this SE.

Source Terms

The licensee used the ORIGEN-2.1 computer code to generate the core radionuclide inventory for use in determining the bounding source term. The licensee used the following inputs to determine the bounding source term:

- An enrichment range of 1.5 weight percent to 5.0 weight percent uranium-235,

- A power level of 3030 MWt (3020 MWt plus 0.3 percent calorimetric uncertainty),

- A core average burnup of up to 49,000 MWd/MTU.

The licensee revised the primary coolant source term as determined for EPU conditions based upon maximum equilibrium concentrations of isotopes with small defects in 1 percent of the fuel rod cladding. The licensee derived the primary coolant corrosion product inventory from ANSI/ANS-18.1-1999.

The licensee adjusted the primary coolant iodine activities to achieve the TS 3.4.8 limit of 1.0 µCi/gm Dose Equivalent (DE) I-131. The non-iodine species are adjusted to achieve a proposed TS limit of 518.9 µCi/gm DE Xe-133 using effective air submersion dose conversion factors (DCFs) from Table III.1 of Federal Guidance Report No. 12. The licensee derived the proposed TS DE Xe-133 limit from the prior TS 100/E-bar limit for non-iodine isotopes, such that the air submersion dose produced by the non-iodine isotopes would be approximately the same.

The licensee evaluated releases from the secondary coolant system activity by assuming the TS limited value of ≤ 0.10 µCi/gm DE I-131. The licensee assumed that noble gases entering the secondary coolant system are immediately released resulting in a noble gas activity concentration in the secondary coolant system of 0.0 µCi/gm.

Dose Conversion Factors

The licensee used committed effective dose equivalent (CEDE) and effective dose equivalent (EDE) dose conversion factors (DCFs) from Federal Guidance Reports (FGR) 11 and 12, as is appropriate for an AST evaluation. The use of ORIGEN and DCFs from FGR 11 and FGR 12 is in accordance with RG 1.183 guidance and is acceptable to the NRC staff.

Atmospheric Dispersion Estimates

In the application dated February 25, 2011, the licensee generated new CR, EAB, and LPZ atmospheric dispersion factors (χ/Q values) for use in evaluating the radiological consequences of the limiting DBAs. The CR χ/Q values were based on meteorological measurements made from 2001 through 2004 and 2006. The EAB and LPZ χ/Q values were calculated using the measurements from 2004 through 2007. The licensee provided a description of the methodologies, other inputs, and assumptions used to calculate the χ/Q values. During the NRC staff's review, requests for RAIs dated July 21, 2011 (ADAMS Accession No. ML112010592), were issued to the licensee. Based on the RAIs, the licensee provided revisions to the original data sets outlined in RAI responses dated October 5, 2011 (ADAMS Accession No. ML11290A065), and November 14, 2011 (ADAMS Accession No. ML11251A159). The revised CR, EAB and LPZ χ/Q values used in this analysis are based on data from the years 1997, 1998, 1999, 2002, and 2003.

Meteorological Data

The licensee provided the initial meteorological data set for years 2001 through 2004 and 2006 in the form of hourly data formatted for input into the ARCON96 atmospheric dispersion computer code (NUREG/CR-6331, Revision 1, "Atmospheric Relative Concentrations in Building Wakes"). In addition, the licensee provided the meteorological data for the 2004 through 2007 period in the form of a joint wind speed, wind direction, and atmospheric stability frequency distribution (JFD) for input to the PAVAN atmospheric dispersion computer code

(NUREG/CR-2858, “PAVAN: An Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radiological Materials from Nuclear Power Stations”).

The meteorological data originated from the meteorological measurements program for the St. Lucie Plant. This program is described in detail in Section 2.3.3 of the Unit 2 FSAR. The on-site meteorological program is designed to provide dispersion climatology for use in the planning of radioactive effluent releases and as a means of determining the meteorological parameters to be used in estimating the potential radiological consequences of hypothetical accidents. The licensee periodically acquired and saved the data from the meteorological tower data logging system and converted the data from the individual time period files to a common spreadsheet format. During processing of annual composite spreadsheet files, the licensee checked the meteorological data for validity. In certain files, stability class was not recorded for extended time periods, but temperature data at 10 and 57.9 meter elevations was available so that stability class could be calculated from this data using the vertical temperature difference in accordance with guidance in RG 1.23. Where data from “A” channel of the logging system was valid at 10 and 57.9 meters, it was used for the stability calculation. If data from “A” channel was missing or invalid and “B” was available and valid, it was used.

In response to the NRC staff’s July 21, 2011, RAIs on the initial meteorological data, the licensee reviewed the data files with METD (NUREG-0917, “Nuclear Regulatory Commission Staff Computer Programs for Use with Meteorological Data”) and manual/visual plotting tools. Based on this higher level of screening, the licensee chose to replace the original submittal data set with a new set of screened and validated data. The METD programs were used to screen the original submittal data set, as well as a replacement 5 year data set. All available meteorological data (1996 (partial), 1997, 1998, 1999, 2000 (partial), 2001, 2002, 2003, 2004, 2006, 2007, 2008, and 2010) were evaluated. Application of METD and manual/visual trend plotting tools identified five years in which the minimum recovery percentage of 90 percent, as outlined in RG 1.23 Section C-5, was met for both ARCON96 and PAVAN inputs. The years were 1997, 1998, 1999, 2002, and 2003.

The revised meteorological data set does not show the same anomalous high number of consecutive hours of same-stability-class behavior, persistent winds from one direction for extended periods of time, or anomalous (multiples of 10, or severely rounded) values that occurred in the initial data set and were noted in the NRC staff’s July 21, 2011, RAIs. The licensee’s screening tools identified such anomalies, and when confirmed to be anomalous, the data was eliminated from the final data set used for χ/Q determination. No data substitution was applied by the licensee to assign 57.9 meter data to 10 meter values during this post processing activity.

NRC staff performed a quality review of the revised meteorological data. The staff found wind direction frequency distributions were reasonably similar from year to year between both measurement heights. Wind speed frequency distributions were also found to be similar from year to year for each measurement level. For the atmospheric stability, measured as the temperature difference between the 57.9 meter and 10.0 meter levels, the time of occurrence and duration of reported stability conditions were generally consistent with the expected meteorological conditions of neutral and slightly stable conditions predominating during the year, stable and neutral conditions occurring at night, and unstable and neutral conditions occurred during the day. Also, a comparison of the JFD derived by the NRC staff from the ARCON96 formatted hourly data to the JFD developed by the licensee for input into the PAVAN atmospheric dispersion model showed good agreement.

On the basis of this review, NRC staff determined that the revised meteorological data provided an acceptable basis for making estimates of atmospheric dispersion for the proposed EPU LAR for St. Lucie 2.

Control Room Atmospheric Dispersion Factors

The licensee used the revised data set from the years 1997, 1998, 1999, 2002, and 2003 to generate control room (CR) χ/Q values using the ARCON96 computer code and guidance provided in NRC RG 1.194: "Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants", which states that ARCON96 is an acceptable methodology for assessing CR χ/Q values for use in DBA radiological analyses. The NRC staff determined that there was no unusual siting, building arrangements, release characterization, release-receptor configuration, meteorological regimes, or terrain conditions that precluded the use of the ARCON96 model in support of the LAR for St. Lucie 2.

The wind speed, wind direction, and atmospheric stability measured at the 10.0 meter and 57.9 meter heights above ground level served as inputs for the CR χ/Q calculations. Other inputs included the release/source height, the CR receptor heights, and the straight-line distance between the source and intake/receptor, all in meters. The direction between intake to source in degrees, the default values of 0.2 meters for surface roughness, 0.5 m/s for minimum wind speed, and a sector averaging constant of 4.3 (found in Table A-2 of RG 1.194) were also used. No diffuse area sources were used in the estimated χ/Q analysis for the purpose of dose assessment.

The licensee notes in the October 5, 2011, RAI responses that the release heights are calculated as 19 ft. less than the referenced elevations to account for plant grade elevation. The elevations for the MSSV and ADV are based on the Unit 1 values with slight adjustments based on height estimates from a walkdown. The RWT release height is scaled from plant drawings. The FHB's closest release point elevation is taken as the roof elevation since the SW corner of the roof is the closest building point to the CR intakes. Release and receptor points are considered to be at the center point or centerline of all openings. Releases from the plant stack have release/receptor combinations that do not have the intakes in the same wind direction window. The licensee takes credit for intake dilution for these releases as allowed per Section 3.3.2.2 of RG 1.194.

The receptor point for the CR is taken as being on the outside of the CR east wall. The receptor elevation is taken as the average of the receptor elevations for the two outside air intakes. Atmospheric dispersion factors for the releases to the midpoint between the CR intakes are required for the limiting case to be used during the time period when the CR intakes are isolated. The midpoint receptor location is used to calculate the χ/Q value to be used for the unfiltered CR inleakage dose. The closest containment/shield building penetration to the intakes that is directly exposed to the atmosphere is the closest FW line penetration.

NRC staff reviewed the licensee's ARCON96 control room atmospheric dispersion estimates. This included a review of the inputs and assumptions which the NRC staff found generally consistent with site configuration drawings, input tables, and the NRC staff practice. In addition, the NRC staff generated sample comparative χ/Q value estimates and found the resultant χ/Q values to be similar to the revised values calculated by the licensee. On the basis of this review, the NRC staff determined that the CR χ/Q values in Table 2 of this SE are acceptable for use in DBA CR dose assessments.

Offsite Atmospheric Dispersion Factors

The licensee generated a JFD using the revised meteorological data set of screened and validated data from the years 1997, 1998, 1999, 2002, and 2003. The licensee calculated EAB and LPZ offsite χ/Q values using guidance provided in RG 1.145: "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants," and the PAVAN atmospheric dispersion computer code. All releases were modeled as ground-level pursuant to guidance provided in RG 1.145 in which no release heights were more than 2.5 times the adjacent structures. Atmospheric stability class was calculated using the temperature difference between the 57.9 meter and 10.0 meter heights on the primary meteorological tower.

In the offsite χ/Q determinations, the licensee assumed a minimum containment cross-sectional area of 1565 m^2 and a containment height of 62.9 meters above ground level. The licensee considered an overall site ground-level EAB distance of 1442 meters and LPZ distance of 1490 meters.

NRC staff performed a qualitative review of the inputs and assumptions used in the licensee's PAVAN computer calculations and the resulting χ/Q values. Staff calculated comparative χ/Q values, and found the results to be similar to the revised EAB and LPZ χ/Q values calculated by the licensee. Therefore, on the basis of this review, the NRC staff determined that the resulting offsite EAB and LPZ χ/Q values generated by the licensee and presented in Table 3 of this SE are acceptable for use in DBA dose assessments.

Atmospheric Dispersion Factor Summary

NRC staff reviewed the revised meteorological data provided in support of this application and determined that it serves as an acceptable basis for making atmospheric dispersion estimates. The NRC staff's review of the CR, EAB, and LPZ χ/Q values found that the licensee used methodologies, assumptions, and inputs consistent with applicable regulatory guidance. The NRC staff determined that the CR χ/Q values generated by the licensee and presented in Table 2 of this SE are acceptable for use in DBA CR dose assessments. Additionally, the NRC staff determined that the offsite χ/Q values generated by the licensee and presented in Table 3 of this SE are acceptable for use in DBA dose assessments.

2.9.2.1 EPU LOCA Radiological Consequences

2.9.2.1.1 Description of Event

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 as specified in RG 1.183. This general scenario does not represent any specific accident sequence, but is representative of a class of severe damage incidents that were evaluated in the development of the RG 1.183 source term characteristics. Such a scenario would be expected to require multiple failures of systems and equipment and lies beyond the severity of incidents evaluated for design basis transient analyses.

The LOCA considered in this evaluation is a complete and instantaneous circumferential severance of the primary RCS piping, which would result in the maximum fuel temperature and primary containment pressure among the full range of LOCAs. Due to the postulated loss of core cooling, the fuel heats up, resulting in the release of fission products. The fission product release is assumed to occur in phases over a 2-hour period.

When using the AST for the evaluation of a DBLOCA for a PWR, it is assumed that the initial fission product release to the containment will last for 30 seconds and will consist of the radioactive materials dissolved or suspended in the RCS liquid. After 30 seconds, fuel damage is assumed to begin and is characterized by clad damage that releases the fission product inventory assumed to reside in the fuel gap. The fuel gap release phase is assumed to continue until 30 minutes after the initial breach of the RCS. As core damage continues, the gap release phase ends and the early in vessel release phase begins. The early in-vessel release phase continues for the next 1.3 hours. The licensee used the LOCA source term release fractions, timing characteristics, and radionuclide grouping as specified in RG 1.183 for evaluation of the AST.

In the evaluation of the LOCA design basis radiological analysis, the licensee considered dose contributions from the following potential activity release pathways:

- Containment leakage via the secondary containment system.
- Containment leakage bypassing the secondary containment.
- ESF system leakage into the RAB.
- ESF system leakage into the RWT.
- Hydrogen purge at event initiation.

The licensee considered the following potential DBLOCA dose contributors to the control room habitability envelope (CRHE) analysis:

- Contamination of the CR atmosphere by intake and infiltration of radioactive material from the containment leakage and ESF system leakage.
- External radioactive plume shine contribution from the containment and ESF leakage releases with credit for CR structural shielding.
- A direct shine dose contribution from the containment's contained accident activity with credit for both containment and CR structural shielding.
- A direct shine dose contribution from the activity collected on the CR ventilation filters.

2.9.2.1.2 Analysis Parameters and Assumptions

2.9.2.1.2.1 LOCA Source Term

The licensee followed all aspects of the guidance outlined in RG 1.183, Regulatory Position 3, regarding the core inventory and the release fractions and timing for the evaluation of the LOCA.

The LOCA analysis assumes that iodine will be removed from the containment atmosphere by both CSs and natural diffusion to the containment walls. As a result of these removal mechanisms, a large fraction of the released activity will be deposited in the containment sump. The sump water will retain soluble gaseous and soluble fission products, such as iodines and cesium, but not noble gases. The guidance from RG 1.183 specifies that the iodine deposited in the sump water can be assumed to remain in solution as long as the containment sump pH is maintained at or above 7.

The licensee conducted an evaluation of containment sump pH and has determined that the sump pH will be maintained at or above 7. This ensures that particulate iodine deposited into the containment sump water will not re-evolve beyond the amount recognized in the DBLOCA analysis. Therefore, in accordance with the applicable regulatory guidance, the licensee assumed that the chemical form of the radioiodine released to the containment is 95 percent cesium iodide (CsI), 4.85 percent elemental iodine, and 0.15 percent organic iodide. With the exception of elemental iodine and organic iodide and noble gases, fission products are assumed to be in particulate form.

2.9.2.1.2.2 Assumptions on Transport in the Primary Containment

2.9.2.1.2.2.1 Containment Mixing, Natural Deposition, and Leak Rate

Section 6.0 of the St. Lucie 2 FSAR describes the containment structure as a steel containment vessel surrounded by a reinforced concrete shield building. The two structures are separated by an annular air space. The containment vessel is a low leakage, cylindrical, steel shell with hemispherical dome and ellipsoidal bottom. The vessel is designed to contain the radioactive material that could be released from a loss of integrity of the RCPB. The shield building is a concrete structure that protects the containment vessel from external missiles, provides biological shielding, and provides a means of controlling radioactive fission products that could leak from the containment vessel if an accident should occur.

In accordance with RG 1.183, the licensee assumed that the activity released from the fuel is mixed instantaneously and homogeneously throughout the free air volume of the containment. The licensee used the core release fractions and timing, as specified in RG 1.183, with the termination of the release into containment set at the end of the early in-vessel phase.

The licensee credited the reduction of airborne radioactivity in the containment by natural deposition. The licensee credited an elemental iodine natural deposition removal coefficient of 2.89 hr^{-1}. The licensee did not credit the removal of organic iodide by natural deposition. The licensee applied the elemental iodine natural deposition removal coefficient of 2.89 hr^{-1} to both the sprayed and unsprayed volume of the containment.

The licensee credited a natural deposition removal coefficient of 0.1 hr^{-1} for all aerosols in the unsprayed region of containment. In addition, the licensee credited a natural deposition removal coefficient of 0.1 hr^{-1} for all aerosols in the sprayed region after spray is terminated at 8 hours.

RG 1.183, Regulatory Position 3.7 states that, "The primary containment should be assumed to leak at the peak pressure technical specification leak rate for the first 24 hours. For PWRs, the leak rate may be reduced after the first 24 hours to 50 percent of the technical specification leak rate." Accordingly, the licensee assumed a containment leak rate of 0.5 percent per day for the first 24 hours, after which the containment leak rate is reduced to 0.25 percent per day for the duration of the accident.

2.9.2.1.2.2.2 CS Assumptions

RG 1.183, Appendix A, Regulatory Position 3.3 states that, "The containment building atmosphere may be considered a single, well mixed volume if the spray covers at least 90 percent of the volume and if adequate mixing of unsprayed compartments can be shown." In addition, SRP Section 6.5.2, III,1, c states, "The containment building atmosphere may be considered a single, well mixed space if the spray covers regions comprising at least 90 percent of the containment building space and if a ventilation system is available for adequate mixing of any unsprayed compartments."

For St. Lucie 2, the volume of the sprayed region is 2,125,000 ft^3 and the volume of the unsprayed region is 375,000 ft^3. Since the sprayed region represents approximately 85 percent of the total containment volume, the licensee used a two volume model to represent the sprayed and unsprayed regions of the containment. The licensee assumed a mixing rate of two turnovers of the unsprayed region per hour which equates to 12,500 cfm. This assumption is in accordance with RG 1.183, Appendix A, Regulatory Position 3.3 which states in part that, "The evaluation of the CSs should address areas within the primary containment that are not covered by the spray drops. The mixing rate attributed to natural convection between sprayed and unsprayed regions of the containment building, provided that adequate flow exists between these regions, is assumed to be two turnovers of the unsprayed regions per hour, unless other rates are justified."

Using the guidance from SRP 6.5.2, the licensee determined that the aerosol removal rate from the effects of the containment spay system, which actuates 0.0222 hours (80 seconds) after the LOCA, is 6.52 per hour until a decontamination factor (DF) of 50 is reached at 2.643 hours post-LOCA. After the DF of 50 is reached, the licensee assumed that the aerosol removal rate is reduced by a factor of 10 in accordance with the applicable regulatory guidance.

Using the guidance from SRP 6.5.2, the licensee determined that the elemental iodine removal rate from the effects of the containment spay system, which actuates 0.0222 hours (80 seconds) after the LOCA, is in excess of 20 per hour. However, in accordance with the guidance in SRP 6.5.2, the licensee limited the removal rate constant for elemental iodine to 20 per hour. The licensee applied this elemental iodine removal rate in the dose analysis from the time of spray actuation until the maximum allowable DF of 200 is reached at 3.07 hours post-LOCA.

The NRC staff has reviewed the licensee's application of credit for iodine removal from the operation of the containment spay system and has found that the analysis follows the applicable regulatory guidance, is conservative, and is therefore acceptable.

2.9.2.1.2.3 Assumptions on Dual Containments

The St. Lucie 2 FSAR describes the shield building, also referred to as the secondary containment, as a medium leakage reinforced concrete structure surrounding the containment vessel. The shield building is designed to provide biological shielding during normal operation and LOCA conditions, environmental protection for the containment vessel from adverse atmospheric conditions and external missiles, and a means for collection and filtration of fission product leakage from the containment vessel following a LOCA. Physically, the shield building is a right circular cylinder with a shallow dome roof.

The licensee assumed that the leakage from primary containment will be collected by the secondary containment and processed by the ESF SBVS filters prior to release from the plant stack. The licensee credited secondary containment filtration efficiencies of 95 percent for elemental iodine and organic iodide and 99 percent for particulates. The licensee assumed that the leakage into the secondary containment is released directly to the environment as a ground-level release prior to the effective drawdown of the secondary containment which is assumed to be completed at 310 seconds after accident initiation.

The licensee credited the SBVS as being capable of maintaining the shield building annulus at a negative pressure with respect to the outside environment considering the effect of high wind speeds and LOCA heat effects on the annulus as described in FSAR. The licensee stated that no exfiltration through the concrete wall of the Shield Building is expected to occur. The licensee did not credit dilution of the primary containment leakage within the secondary containment volume. In addition, the licensee assumed that 9.6 percent of the primary containment leakage will bypass the secondary containment and be released at ground level without credit for filtration.

2.9.2.1.2.4 Assumptions on ESF System Leakage

To evaluate the radiological consequences of ESF leakage, the licensee used the deterministic approach as prescribed in RG 1.183. This approach assumes that except for the noble gases, all of the fission products released from the fuel mix instantaneously and homogeneously in the containment sump water. Except for iodine, all of the radioactive materials in the containment sump are assumed to be in aerosol form and retained in the liquid phase. As a result, the licensee assumed that the fission product inventory available for release from ECCS leakage consists of 40 percent of the core inventory of iodine. This amount is the combination of 5 percent released to the containment sump water during the gap release phase and 35 percent released to the containment sump water during the early in vessel release phase. This source term assumption is conservative in that 100 percent of the radioiodines released from the fuel are assumed to reside in both the containment atmosphere and in the containment sump concurrently. ECCS leakage develops when ESF systems circulate containment sump water outside containment and leaks develop through packing glands, pump shaft seals and flanged connections.

For the LOCA analysis of ESF leakage, the licensee used a value of 1.08 gallons per hour (gph), representing two times the allowed value, as specified in RG 1.183, Appendix A, Item 5.2.

The licensee assumed that ESF leakage will start at 22.3 minutes into the event, coinciding with the beginning of the recirculation phase of emergency core cooling, and continue for the 30 day duration of the accident evaluation.

2.9.2.1.2.4.1 Assumptions on ESF System Leakage to the RAB

RG 1.183, Appendix A, Regulatory Position 5.5, states that, "If the temperature of the leakage is less than 212 °F or the calculated flash fraction is less than 10 percent, the amount of iodine that becomes airborne should be assumed to be 10 percent of the total iodine activity in the leaked fluid."

The licensee calculated the fractional iodine release or flashing fraction for ESF leakage as 5.7 percent. However, the licensee used a flashing fraction of 10 percent, as prescribed in RG 1.183, for conservatism. The licensee has determined that the pH of the containment sump will not fall below 7.0 for the duration of the accident.

The licensee assumed that the ECCS leakage is released directly into the RAB and released instantaneously into the environment with credit for RAB ECCS area filtration. The licensee credited ECCS area filtration efficiencies of 95 percent for elemental iodine and organic iodide and 99 percent for particulates. As noted previously, the licensee assumed that 100 percent of the particulate activity is retained in the sump water. The licensee did not credit a reduction of activity released to the RAB as a result of dilution or holdup.

In accordance with RG 1.183, for ESF leakage into the RAB, the licensee assumed that the chemical form of the released iodine is 97 percent elemental iodine and 3 percent organic.

The NRC staff has reviewed the licensee's analysis of the dose consequence from ECCS leakage and has determined that the analysis follows the applicable regulatory guidance, is conservative, and is therefore acceptable.

2.9.2.1.2.4.2 Assumptions on ESF System Back leakage to the RWT

The licensee evaluated the dose consequence from ECCS backleakage to the RWT by assuming an initial backleakage rate of 2 gpm based upon doubling the allowed value of 1 gpm. The licensee assumed that this leakage starts at 22.3 minutes into the event when recirculation begins and continues throughout the 30-day analysis period. Based on sump pH remaining at 7 or above, the iodine in the sump solution is assumed to all be nonvolatile. However, when introduced into the acidic solution of the RWT inventory, there is a potential for the particulate iodine to convert into the elemental iodine form. The fraction of the total iodine in the RWT that becomes elemental iodine is both a function of the RWT pH and the total iodine concentration. The amount of elemental iodine in the RWT fluid that then enters the RWT air space is a function of the temperature-dependent iodine partition coefficient.

The licensee determined the time-dependent concentration of the total iodine in the RWT from the tank liquid volume and leak rate. The licensee calculated that the total iodine concentration ranged from a minimum value of 0 at the beginning of the event to a maximum value of 4.088E-05 gm-atom per liter at 30 days.

Based upon the backleakage of sump water, the licensee determined that the RWT pH slowly increases from an initial value of 4.5 to a maximum pH of 4.864 at 30 days. Using the time-dependent RWT pH and the total iodine concentration in the RWT liquid space, the licensee determined the amount of iodine that will be converted to the elemental iodine form using the guidance provided in NUREG/CR-5950. The licensee determined that the RWT elemental iodine concentration will range from 0 at the beginning of the event to a maximum of 3.462E-06 gm-atom per liter at 30 days.

The licensee assumed that the elemental iodine in the liquid region of the RWT will become volatile and partition between the liquid and vapor space in the RWT based upon the partition coefficient for elemental iodine as described in NUREG/CR-5950. The licensee developed a model using the GOTHIC computer code to determine the RWT temperature as a function of time. The licensee conservatively used the peak temperature to calculate the elemental iodine partition coefficient for the full 30 day analysis period.

Because the RWT is vented to the atmosphere, there will be no pressure transient in the air region that would affect the partition coefficient. Since no boiling occurs in the RWT, the licensee calculated the flow rate of the released activity from the vapor space within the RWT based upon the displacement of air by the incoming backleakage. The licensee calculated the elemental iodine release rate from the RWT by multiplying the displacement air flow rate times the elemental iodine concentration in the RWT vapor space.

The licensee used the same approach to evaluate the organic iodide release rate from the RWT. The licensee used an organic iodide fraction of 0.0015 from RG 1.183 in combination with a partition coefficient of 1.0 for organic iodide. Consistent with RG 1.183 guidance, the licensee assumed that the particulate portion of the leakage is retained in the liquid phase of the RWT. Therefore, the total iodine release rate is the sum of the elemental iodine and organic iodide release rates.

The NRC staff has reviewed the licensee's analysis of the dose consequence from ECCS backleakage into the RWT and has determined that the analysis follows the applicable regulatory guidance, is conservative, and is therefore acceptable.

2.9.2.1.2.5 Assumptions on Containment Hydrogen Purging

The licensee evaluated the radiological effects of containment leakage via open hydrogen purge lines, which is assumed to occur for the first 30 seconds of the DBLOCA. The licensee assumed that 100 percent of the radionuclide inventory of the RCS is released instantaneously into the containment at the beginning of the event. The containment hydrogen purge consists of a volumetric flow rate of 2500 cfm released to the environment via the plant vent for a period of 30 seconds with no credit for filtration.

During the time period of 30 seconds following accident onset, the licensee assumes that fuel failure has not occurred. This assumption follows the guidance in Table 4 of RG 1.183, which indicates that the initial release of the RCS into containment for a PWR would occur within the first 30 seconds of the accident prior to the onset of fuel damage. Per RG 1.183, the hydrogen purge release evaluation should assume that 100 percent of the radionuclide inventory in the RCS liquid is released to the containment at the initiation of the LOCA and that this inventory should be based on the TS RCS equilibrium activity.

The licensee used conservative assumptions to evaluate the containment hydrogen purge contribution to the LOCA dose and therefore, the NRC staff finds this evaluation acceptable for the EPU LOCA analysis.

2.9.2.1.2.6 Control Room Habitability for the LOCA

2.9.2.1.2.6.1 CR Ventilation Assumptions for the LOCA

The Control Room Air Conditioning System (CRACS) and Control Room Emergency Ventilation System (CREVS) are required to assure CR habitability. The design of the CR envelope and overall descriptions of both the CRACS and the CREVS are contained in Sections 6.4 and 9.4.1 of the St. Lucie 2 FSAR.

During normal plant operation, the control room envelope is pressurized relative to the surrounding areas at all times with outside air continuously introduced to the control room envelope at a rate of 750 cfm. For conservatism, the licensee used a value of 1000 cfm in the dose analyses.

For the LOCA analysis, the CR ventilation system is initially assumed to be operating in normal mode. The air flow distribution during the normal mode of operation is 1000 cfm of unfiltered fresh air with an assumed value of 395 cfm for unfiltered inleakage. After the start of the event, the CR is assumed to be isolated due to a containment isolation actuation signal (CIAS) as a result of a high containment pressure signal. The licensee applied a 30-second delay to account for the time required to reach the CIAS, the time to start the diesel generator and the time for damper actuation. After isolation, the air flow distribution is assumed to consist of 0 cfm of makeup flow from the outside, 395 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

At 1.5 hours into the event, the operators are assumed to initiate makeup flow from the outside into the control room to restore a positive pressure differential and to maintain air quality. Makeup air for CR pressurization is filtered before entering the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 395 cfm of assumed unfiltered inleakage and 1256 cfm of filtered recirculation flow. The licensee conservatively modeled CR ventilation flow rates by taking into consideration variations in frequency and voltage of the diesel generators as well as tolerances in the CR ventilation test acceptance criteria.

The CR ventilation filter efficiencies that are applied to the filtered makeup and recirculation flows are 99 percent for particulates, 95 percent for elemental iodine, and 95 percent for organic iodide.

2.9.2.1.2.6.2 CR Direct Shine Dose Assumptions

The total CR LOCA dose includes direct shine contributions from the following DBLOCA radiation sources:

- Contamination of the CR atmosphere by the intake and infiltration of the radioactive material contained in the radioactive plume released from the facility.

- Direct shine from the external radioactive plume released from the facility with credit for CR structural shielding.

- Direct shine from radioactive material in the containment with credit for both the containment and CR structural shielding.

- Radiation shine from radioactive material in systems and components inside or external to the CR envelope including radioactive material buildup on the CR ventilation filters.

RG 1.196 defines the CR envelope (CRE) as follows: “The plant area, defined in the facility licensing basis, that in the event of an emergency, can be isolated from the plant areas and the environment external to the CRE. This area is served by an emergency ventilation system, with the intent of maintaining the habitability of the control room. This area encompasses the control room, and may encompass other non critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident.”

The licensee evaluated the contribution to the total dose to the CR operators from direct radiation sources, such as the control room filters, the containment atmosphere, and the released radioactive plume for the LOCA event. The licensee asserts and the NRC staff agrees that the LOCA shine dose contribution is bounding for all other events. The 30-day direct shine dose to a person in the control room, considering occupancy, is provided in Table 4 of this SE. For conservatism, the licensee assumed the bounding LOCA CR shine dose for all the DBAs evaluated.

The licensee determined the direct shine dose from three different sources to the control room operator after a postulated LOCA event. These sources are the containment, the control room air filters, and the external cloud that envelops the control room. The licensee asserts, and the NRC staff agrees, that per Table 6.4-2 of the FSAR, all other sources of direct shine dose to the CR can be considered negligible. The licensee used the MicroShield 5 shielding code to determine direct shine exposure to a dose point located in the control room. Each source required a different MicroShield case structure that included different geometries, sources, and materials. The licensee modeled the external cloud by assigning a source length of 1000 meters in MicroShield to approximate an infinite cloud. The licensee ran multiple cases to determine an exposure rate from the radiological source at given points in time. These sources were taken from RADTRAD-NAI runs that output the nuclide activity at a given point in time for the event. The RADTRAD-NAI output provides the time dependent results of the radioactivity retained in the control room filter components, as well as the activity inventory in the environment and the containment. A bounding CR filter inventory is established using a case from the sensitivity study with an assumed unfiltered inleakage that produced a control room dose slightly in excess of the 5 rem TEDE dose limit to control room operators without the application of the occupancy factors described in RG 1.183. The direct shine dose calculated due to the filter loading for this conservative unfiltered inleakage case is used as a conservative assessment of the direct shine dose contribution for all accidents.

The RADTRAD-NAI sources were then input into the MicroShield case file to yield the source activity at a later point in time. The exposure results from the series of cases for each source term were then corrected for occupancy using the occupancy factors specified in RG 1.183. The cumulative exposure and dose are subsequently calculated to yield the total 30-day direct shine dose from each source. The results of the licensee’s CR direct shine dose evaluation are presented in Table 4 of this SE.

The NRC staff finds that the licensee's evaluation of the potential direct shine dose contributions to the CR LOCA dose analysis used conservative assumptions and sound engineering judgment and is therefore acceptable.

2.9.2.1.3 Conclusion

The licensee evaluated the radiological consequences resulting from the postulated LOCA and concluded that the radiological consequences at the EAB, LPZ, and CR comply with the reference values and the CR dose criterion provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 5 and the licensee's calculated dose results are given in Table 1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a DBLOCA will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

2.9.2.2 Fuel Handling Accident

2.9.2.2.1 Description of Event

This accident analysis postulates that a spent fuel assembly is dropped during fuel handling and strikes an adjacent assembly during the fall. 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 of the 217 assemblies 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 to the surrounding water as a result 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 assumed no decontamination for noble gases, a DF of 200 for radioiodines, and retention of all particulate fission products. As prescribed in RG 1.183, 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 assumptions and inputs are identical for the FHA within containment and the FHA outside containment, the results of the two events are identical.

The licensee considered the analysis of the FHA both within the containment and within the FHB. The dropped fuel assembly inside the containment is assumed to occur with the equipment maintenance hatch fully open and the fuel assembly drop inside the FHB credits no filtration of the exhaust. The water level above the damaged fuel assembly is maintained at 23 feet minimum for release locations both inside containment (i.e., reactor cavity) and the FHB (i.e., SFP). This water cover acts as a barrier to many of the radionuclides released from the dropped assembly. The licensee assumed retention of all non-iodine particulate in the pool, while the iodine releases from the fuel gap into the pool are assumed to be decontaminated by an overall factor of 200. This decontamination factor (DF) results in 0.5 percent (i.e., 99.5 percent of the iodine are retained in the pool) of the radioiodine escaping the overlying water with a composition of 70 percent elemental iodine and 30 percent organic. In accordance with Regulatory Position 3 of RG 1.183, the licensee assumes 100 percent of the noble gas exits the pool. All fission products released to the environment occurs over a two hour period. In the subject FHA analysis, the licensee does not credit dilution within the surrounding structures prior to release to the atmosphere. These assumptions follow the guidance of RG 1.183 and are therefore acceptable to the staff.

2.9.2.2.2 Analysis Parameters and Assumptions

2.9.2.2.2.1 FHA Source Term

For the purpose of this analysis, the licensee assumed a conservative estimate of 72 hours decay time for the movement of fuel, as accounted for in the RADTRAD code analysis. This indicates that any fuel accounted for in the analyzed FHA would have experienced radioactive decay for a period of 72 hours prior to any susceptibility to dropping either in the reactor cavity or SFP. The core fission product inventory that constitutes the source term for this event is the gap activity in all 236 fuel rods in one assembly that are assumed to be damaged as a result of the postulated design basis FHA. Volatile constituents of the core fission product inventory migrate from the fuel pellets to the gap between the pellets and the fuel rod cladding during normal power operations. The fission product inventory in the fuel rod gap of the damaged fuel rods is assumed to be instantaneously released to the surrounding water as a result of the accident per Regulatory Position 1.2 of RG 1.183.

Guidance provided in RG 1.183, Footnote 11, states that the gap activity release fractions, as specified in Table 3 of RG 1.183, have been determined acceptable for use with currently approved LWR fuel with a peak burnup up to 62,000 MWd/MTU provided that the maximum linear heat generation rate does not exceed 6.3 kW/ft peak rod average power for burnups exceeding 54,000 MWD/MTU. In order to account for the gap fraction uncertainty in fuel that does not meet the criteria specified in Footnote 11 of RG 1.183, the licensee conservatively adjusted these gap fractions by a factor of 2.0 as discussed below.

The licensee stated that at EPU conditions the high burnup rods will continue to remain below the limitations of RG 1.183 Footnote 11. However, for conservatism, the licensee assumed that a number of fuel rods equivalent to two fuel assemblies (2 x 236 = 472 fuel rods) would exceed the limitations of RG 1.183, Footnote 11. Considering 217 assemblies in the core, the assumed 2 high burnup assemblies represent 0.922 percent of the core. The licensee doubled the activity gap fractions for all rods in two assemblies to account for the high burnup rods that exceed the limits specified in RG 1.183. Doubling the gap release fraction of 0.922 percent of the core yields a core-wide high burnup adjustment factor of 1.00922. The licensee applied this factor to the release fractions for all events in which fuel damage causes the core wide inventory of the fuel rod gaps to be released into the reactor coolant. For the FHA, in which 100 percent of the rods in the dropped fuel assembly are assumed to release their gap activity, the licensee addressed the high burnup issue by increasing the gap release fraction of the entire assembly by a factor of 2.0. The licensee stated that the number of rods exceeding the burnup limitations of RG 1.183, Footnote 11 will be controlled through the core design process by verifying on a cycle-by-cycle basis that the number of rods exceeding this limit remains below 472. The staff concludes that the licensee’s approach to the evaluation of the potential for high burnup rods at St. Lucie 2 is conservative and therefore acceptable.

2.9.2.2.2.2 Transport

Pursuant to guidance provided in RG 1.183, the St. Lucie 2 FHA is analyzed based on the assumption that all of the fission products released from the reactor cavity or SFP are released to the environment over a two hour period. The licensee utilized a ground-level release for all scenarios considered for the subject FHA. A drop of a single fuel assembly and a subsequent release from the closest point of the FHB to the CR was found to be the most limiting FHA.

For the FHA occurring inside containment, the licensee assumed that the equipment maintenance hatch is open at the time of the accident and that the release from the containment occurs with no credit taken for containment isolation, no credit for dilution or mixing in the containment atmosphere, and no credit for filtration of the released effluent. For the FHA occurring in the FHB, the licensee also assumed no credit for filtration of the activity released from the SFP water prior to being released to the environment.

As corrected by item 8 of RIS 2006-04 (Reference 61), RG 1.183, Appendix B, Regulatory Position 2, should read as follows:

> "If the depth of water above the damaged fuel is 23 feet or greater, the decontamination factors for the elemental iodine and organic species are 285 and 1, respectively, giving an overall effective decontamination factor of 200 (i.e., 99.5 percent of the total iodine released from the damaged rods is retained by the water). This difference in decontamination factors for elemental iodine(99.85 percent) and organic iodide (0.15 percent) species results in the iodine above the water being composed of 70 percent elemental iodine and 30 percent organic species."

As noted previously, the licensee assumed a minimum water depth of 23 feet covers the underlying damaged fuel assembly in both the reactor cavity and SFP for the FHA analyzed in the subject LAR. The assumed 176 damaged fuel rods in the pool releases 100 percent of its gap activity within the water, which is scrubbed by the water column as it rises throughout. This scrubbing decontaminates the gap releases with an overall DF of 200. This DF results in 0.5 percent (i.e., 99.5 percent of the iodine are retained in the pool) of the radioiodine escaping the overlying water with a composition of 70 percent elemental iodine and 30 percent organic iodide. Additionally, 100 percent of the noble gas is assumed to exit the pool per Regulatory Position 3 of RG 1.183.

2.9.2.2.2.3 CR Ventilation Assumptions for the FHA

In order to evaluate the CR habitability for the postulated design basis FHA, the licensee assumed three modes of operation for the control room. During normal mode of operation (i.e., prior to CR isolation), there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively assumed to be 1000 cfm. After the radiation monitors activate the emergency signal, both north and south CR intakes are closed simultaneously. This occurs approximately 30 seconds into the postulated FHA. Accordingly, the air flow distribution during this post CR isolation mode consists of 0 cfm of outside makeup flow, 395 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow. After 90 minutes from the onset of the accident, the operator acts to open the more favorable CR air intake based on the output of the radiation monitors, maintaining positive pressure and initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, 395 cfm of assumed unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day event. The licensee considered CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide.

2.9.2.2.3 Conclusion

The licensee evaluated the radiological consequences resulting from a postulated FHA at St. Lucie 2 and concluded that the radiological consequences at the EAB, outer boundary of the LPZ, and CR are within the reference values and the CR dose criterion provided in 10 CFR 50.67 as well as the accident specific dose guidelines specified in SRP 15.0.1. The staff's review has found that the licensee used analyses, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the staff are presented in Table 6 and the licensee's calculated dose results are given in Table 1. The staff finds that all doses estimated by the licensee for the St. Lucie 2 FHA will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

2.9.2.3 MSLB Accident

2.9.2.3.1 Description of Event

The postulated MSLB accident assumes a double ended break of a main steam line. This leads to an uncontrolled release of steam from the steam system. The resultant depressurization of the steam system causes the MSIVs to close and, if the plant is operating at power when the event is initiated, causes the reactor to trip. For the MSLB DBA radiological consequence analysis, a LOOP is assumed to occur shortly after the trip signal. Following a reactor trip and turbine trip, the radioactivity is released to the environment through the SG PORVs. Because the LOOP renders the main condenser unavailable, the plant is cooled down by releasing steam to the environment.

The licensee evaluated the radiological consequences of a MSLB outside containment. In addition, the licensee considered the radiological consequences of a MSLB inside containment. For the MSLB outside containment, the affected SG, hereafter referred to as the faulted SG, rapidly depressurizes and releases the initial contents of the SG to the environment. For the MSLB inside containment, the faulted SG rapidly depressurizes and releases the initial contents of the SG to the containment atmosphere. The MSLB accident is described in Section 15.1 of the St. Lucie 2 FSAR. RG 1.183, Appendix E, identifies acceptable radiological analysis assumptions for a PWR MSLB.

The steam release from a rupture of a main steam line would result in an initial increase in steam flow, which decreases during the accident as the steam pressure decreases. The increased energy removal from the RCS causes a reduction of coolant temperature and pressure. Due to the negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity. In addition, the conservative analysis assumes that the most reactive control rod is stuck in its fully withdrawn position after the reactor trip, thereby increasing the possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid delivered by the safety injection system.

2.9.2.3.2 Analysis Parameters and Assumptions

2.9.2.3.2.1 MSLB Source Term

Appendix E of RG 1.183 identifies acceptable radiological analysis assumptions for a PWR MSLB accident. RG 1.183, Appendix E, Regulatory Position 2, states that if no or minimal fuel damage is postulated for the limiting event, the released activity should be the maximum coolant activity allowed by TS including the effects of pre-accident and concurrent iodine spiking. The licensee's evaluation indicates that fuel damage is assumed to occur as a result of a MSLB accident. The licensee determined that the activity released from the damaged fuel will exceed that released by the two iodine spike cases. Therefore, the licensee performed the MSLB dose consequence analysis based on the assumption of fuel damage and did not analyze the two iodine spike cases.

The licensee determined the allowable levels of fuel failure for DNB and fuel centerline melt for both the MSLB outside of containment and the MSLB inside of containment. These allowable fractions are based on the dose limits specified in Table 6 of RG 1.183. In a letter dated March 18, 2008 (ADAMS Accession No. ML080850561), the licensee provided additional information regarding the assumed values of fuel failure used in the AST analyses. The licensee stated that the analyzed fuel failure values used in the AST dose analyses do not represent values that are indicative of those that would be predicted by the core reload analyses. The licensee further stated that typical cycle-specific fuel failures as predicted by core reload analyses are much less than the fuel failure limits established in the AST DBA dose analyses. Similarly, cycle-specific fuel failures as predicted by core reload analyses are expected to be less than the fuel failure limits established in the EPU AST DBA dose analyses.

The licensee based the MSLB source term on the total core inventory of the radionuclide groups as described in RG 1.183, Regulatory Position 3.1. The licensee adjusted the source term for the fraction of fuel damaged and applied a radial peaking factor of 1.65 to the inventory of the damaged fuel. The fraction of fission product inventory in the gap available for release due to DNB is consistent with Regulatory Position 3.2 and Table 3 of RG 1.183. The licensee increased the gap release fractions by a factor of 1.00922 to account for high burnup fuel rods as described previously in this SE. For the fraction of the core that is assumed to experience fuel centerline melt, the licensee applied the guidance provided in RG 1.183, Appendix H, and Regulatory Position 1, to determine the release. This guidance states that the release attributed to fuel melting should be based on the fraction of the fuel that reaches or exceeds the initiation temperature for fuel melting and that for the secondary system release pathway, 100 percent of the noble gases and 50 percent of the iodines in that fraction are released to the reactor coolant.

RG 1.183, Appendix E, Regulatory Position 4 states that, "The chemical form of radioiodine released from the fuel should be assumed to be 95 percent CsI, 4.85 percent elemental iodine, and 0.15 percent organic iodide. Iodine releases from the SGs to the environment should be assumed to be 97 percent elemental iodine and 3 percent organic. These fractions apply to iodine released as a result of fuel damage and to iodine released during normal operations, including iodine spiking." Accordingly, the licensee assumed that the iodine releases to the environment or to the containment from both the faulted SG and the unaffected SG consist of 97 percent elemental iodine and 3 percent organic iodide.

Although the release of secondary coolant activity is not specifically addressed in RG 1.183, 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 LCO of 0.1 µCi/gm DEI.

2.9.2.3.2.2 Transport

The licensee evaluated two cases for the MSLB; one case is based upon a double-ended break of a main steam line outside of containment, and the second case is based upon a double-ended break of a main steam line inside of containment. The primary difference between these two models is the transport of the primary-to-secondary leakage through the affected SG. The postulated MSLB will result in the rapid depressurization of the affected or faulted SG. The rapid secondary depressurization causes a reactor power transient, resulting in a reactor trip. Plant cooldown is achieved via the remaining unaffected SG. The analysis for both cases assumes that activity is released as reactor coolant enters the SGs due to primary-to-secondary leakage. The licensee adjusted the source term for this activity for the fraction of damaged fuel, the non-LOCA fission product gap fractions from Table 3 of RG 1.183 including an adjustment for high burnup fuel, and an adjustment for a radial peaking factor of 1.65. All noble gases associated with this leakage are assumed to be released directly to the environment.

For both cases, the licensee assumed that the primary-to-secondary leak rate is apportioned equally between the SGs at the rate of 0.5 gpm total with 0.25 gpm to any one SG. This is in accordance with the accident induced leakage performance criteria of the SG Program as described in TS Section 6.8.4.1. This accident induced leakage performance criteria continues to maintain margin to the operational leakage limit specified in the TSs. The SG tube leakage TS limit is 150 gpd per SG which is roughly equivalent to 0.1 gpm. For the break outside containment, the licensee assumed that the primary-to-secondary leakage into the faulted SG is released directly to the atmosphere. For the break inside containment, the licensee assumed that the faulted SG primary-to-secondary leakage is released into containment. The licensee assumed that all primary-to secondary leakage continues until the faulted SG is completely isolated at 12.4 hours.

The licensee followed the guidance as described in RG 1.183, Appendix E, and Regulatory Position 5 in all aspects of the transport analysis for the MSLB. RG 1.183, Appendix E, Regulatory Position 5.2, states that, "The density used in converting volumetric leak rates (e.g., gpm) to mass leak rates (e.g., lbm/hr) should be consistent with the basis of the parameter being converted. The alternate repair criteria (ARC) leak rate correlations are generally based on the collection of cooled liquid. Surveillance tests and facility instrumentation used to show compliance with leak rate TSs are typically based on cooled liquid. In most cases, the density should be assumed to be 1.0 gm/cc (62.4 lbm/ft3)." The density used by the licensee in converting volumetric leak rates to mass leak rates is based upon RCS conditions, which is consistent with the plant design basis. The licensee used a RCS fluid density to convert the primary-to-secondary leakage from a volumetric flow rate to a mass flow rate, which is consistent with the RCS cooldown rate applied in the generation of the secondary steam releases. This methodology follows sound engineering principles and is therefore acceptable to the NRC staff.

RG 1.183, Appendix E, Regulatory Position 5.3, states that, "The primary to secondary leakage should be assumed to continue until the primary system pressure is less than the secondary system pressure, or until the temperature of the leakage is less than 100 °C (212 °F). The release of radioactivity from unaffected SGs should be assumed to continue until SDC is in operation and releases from the SGs have been terminated." In accordance with RG 1.183, the licensee assumed that the primary-to-secondary leakage is assumed to continue until after SDC has been placed in service and the temperature of the RCS is less than 212 ˚F.

In accordance with RG 1.183, the licensee assumed that all noble gas radionuclides released from the primary system are released to the environment without reduction or mitigation. Following the guidance from RG 1.183, Appendix E, Regulatory Positions 5.5.1, 5.5.2 and 5.5.3, the licensee assumed that all of the primary-to-secondary leakage into the faulted SG will flash to vapor, and be released to the environment or to the containment with no mitigation. For the unaffected SG that is used for plant cooldown, the licensee assumed that a portion of the leakage would flash to vapor based on the thermodynamic conditions in the reactor and secondary immediately following a plant trip when tube uncovery is postulated. The licensee assumed that the primary-to-secondary leakage would mix with the secondary water without flashing during periods of total tube submergence.

The licensee assumed that the postulated leakage that immediately flashes to vapor would rise through the bulk water of the SG into the steam space and be immediately released to the environment or to the containment with no mitigation. For conservatism, the licensee did not credit any reduction for scrubbing within the SG bulk water.

RG 1.183, Appendix E, Regulatory Position 5.5.4, states that, "The radioactivity in the bulk water is assumed to become vapor at a rate that is the function of the steaming rate and the partition coefficient. A partition coefficient for iodine of 100 may be assumed. The retention of particulate radionuclides in the SGs is limited by the moisture carryover from the steam generators."

Accordingly, the licensee assumed that the radioactivity in the bulk water of the unaffected SG becomes vapor at a rate that is a function of the steaming rate and the partition coefficient. The licensee used a partition coefficient of 100 for elemental iodine and other particulate radionuclides released from the intact SG.

In accordance with RG 1.183, Appendix E, Regulatory Position 5.6, the licensee evaluated the potential for SG tube bundle uncovery and determined that tube bundle uncovery is postulated to occur in the intact SG for up to 1 hour following a reactor trip for St. Lucie 2. During this period, the licensee assumed that the fraction of primary-to secondary leakage which flashes to vapor would rise through the bulk water of the SG into the steam space and be immediately released to the environment or the containment with no mitigation. The licensee determined the flashing fraction based on the thermodynamic conditions in the reactor and secondary coolant. The licensee assumed that the leakage which does not flash would mix with the bulk water in the SG.

In response to an RAI, the licensee stated that the EPU LAR AST steam release evaluation of each event's steam releases used a combination of event analysis defined state-points, and evaluated a range of cooldown rates for the time periods when operators will cooldown the plant to 212 °F. These cooldown rates are described in the transport section for the SGTR accident and are applicable to other non-SGTR accidents involving secondary side releases as a result of steaming to achieve plant cooldown.

The licensee assumed that operator action would be taken to restore water level above the top of the tubes in the unaffected SG within one hour following a reactor trip. The NRC staff considers that crediting operator action to restore water level above the top of the tubes in the unaffected SG within one hour following a reactor trip to be a conservative and acceptable assumption.

The licensee assumed that all secondary releases would occur from the ADV with the most limiting atmospheric dispersion factors. For the MSLB inside containment, the licensee assumed that releases from containment through the SBVS are released from the plant stack with a filter efficiency of 99 percent for particulates and 95 percent for both elemental iodine and organic iodide. The licensee assumed that 9.6 percent of the containment leakage is assumed to bypass the SBVS filters and is released unfiltered to the environment as a ground-level release from containment. The licensee assumed an initial leak rate from the containment of 0.5 percent of the containment air per day. In accordance with applicable guidance, the licensee reduced this leak rate by 50 percent after 24 hours to 0.25 percent per day. The licensee credited natural deposition of the radionuclides consistent with the LOCA methodology as discussed previously in this SE. The licensee did not credit CSs for the MSLB analysis.

2.9.2.3.2.3 CR Ventilation Assumptions for the MSLB

In order to evaluate the CR habitability for the postulated design basis MSLB, the licensee assumed three modes of operation for the control room ventilation system. During the normal mode of operation prior to CR isolation, there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively assumed to be 1000 cfm with an assumed value of 395 cfm for unfiltered inleakage. After the radiation monitors activate the emergency signal, both the north and south CR intakes are closed simultaneously. This occurs approximately 30 seconds into the postulated MSLB event. Accordingly, the air flow distribution during this post CR isolation mode consists of 0 cfm of outside makeup flow, 395 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

After 90 minutes from the onset of the accident, operator action is credited to open the more favorable CR air intake based on the output of the radiation monitors, maintaining positive pressure and initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, an assumed 395 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day accident evaluation period. The licensee assumed CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide. The CR parameters used in the EPU analyses are shown in Table 4 of this SE.

2.9.2.3.3 Conclusion

The licensee evaluated the radiological consequences resulting from the postulated MSLB accident and concluded that the radiological consequences at the EAB, LPZ, and CR comply with the reference values and the CR dose criterion provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review has found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 7 and the licensee's calculated dose results are given in Table 1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a design basis MSLB will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

2.9.2.4 SGTR Accident

2.9.2.4.1 Description of Event

The SGTR event is described in Section 15.6.3 of the St. Lucie 2 FSAR. The SGTR accident is evaluated based on the assumption of an instantaneous and complete severance of a single SG tube. At normal operating conditions, the leak rate through the double-ended rupture of one tube is greater than the maximum flow available from the charging pumps. For leaks that exceed the capacity of the charging pumps, pressurizer water level and pressurizer pressure decrease and an automatic reactor trip results. The turbine then trips and the main steam dump and bypass valves open, discharging steam directly into the condenser.

The postulated break allows primary coolant liquid to leak to the secondary side of the ruptured SG. Integrity of the barrier between the RCS and the main steam system is significant from a radiological release standpoint. The radioactivity from the ruptured SG tube mixes with the shell side water in the affected SG. As stated in the FSAR, detection of reactor coolant leakage to the steam system is facilitated by radiation monitors in the SG blowdown lines, in the condenser air ejector discharge lines and in the main steam line radiation monitors. These monitors initiate alarms in the CR and alert operators of abnormal activity levels and that corrective action is required.

For the SGTR DBA radiological consequence analysis, a LOOP is assumed to occur shortly after the reactor trip signal. With a LOOP, the cessation of circulating water through the condenser would eventually result in the loss of condenser vacuum, thereby causing steam relief directly to the atmosphere from the ADVs. The licensee assumed that this direct steam relief continues until the ruptured SG is isolated at 45 minutes. This credited operator action after 45 minutes represents a conservative increase in the assumed time for this manual action over the time credited in the CLB SGTR accident.

2.9.2.4.2 Analysis Parameters and Assumptions

2.9.2.4.2.1 SGTR Source Term

Appendix F of RG 1.183 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 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 St. Lucie 2, the maximum iodine concentration allowed by TS as a result of an iodine spike is 60 μCi/gm DEI.

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 an accident-induced iodine spike or a concurrent iodine spike. Initially, the plant is assumed to be operating with the RCS iodine activity at the TS limit for normal operation. For St. Lucie 2, the RCS TS limit for normal operation is 1.0 μCi/gm DEI. The increase in primary coolant iodine concentration for the concurrent iodine spike case is estimated using a spiking model that assumes that as a result of the accident, iodine is released from the fuel rods to the primary coolant at a rate that is 335 times greater than the iodine equilibrium release rate corresponding to the iodine concentration at the TS limit for normal operation. The iodine release rate at equilibrium is equal to the rate at which iodine is lost due to radioactive decay, RCS purification, and RCS leakage. The iodine release rate is also referred to as the iodine appearance rate. The concurrent iodine spike is assumed to persist for a period of eight hours.

The licensee's evaluation indicates that no fuel damage is predicted as a result of an SGTR accident. Therefore, consistent with the CLB and regulatory guidance, the licensee performed the SGTR accident analyses for the pre accident iodine spike case and the concurrent accident iodine spike case. In accordance with regulatory guidance, the licensee assumed that the activity released from the iodine spiking mixes instantaneously and homogeneously throughout the primary coolant system. In accordance with regulatory guidance, the licensee assumed that the iodine releases from the SGs to the environment consist of 97 percent elemental iodine and 3 percent organic iodide.

For the SGTR accident, the licensee evaluated the radiological dose contribution from the release of secondary coolant iodine activity at the TS limit of 0.1 μCi/gm DEI.

2.9.2.4.2.2 Transport

The licensee followed the guidance as described in RG 1.183, Appendix F, Regulatory Position 5, in all other aspects of the transport analysis for the SGTR dose consequence analysis.

In addition to the primary coolant released into the ruptured SG by the tube rupture, the licensee apportioned the primary-to-secondary leak rate is between the SGs as specified by TS 6.8.4.1, which is 0.5 gpm total and 0.25 gpm to any one SG.

RG 1.183, Appendix F, Regulatory Position 5.2, states that, "The density used in converting volumetric leak rates (e.g., gpm) to mass leak rates (e.g., lbm/hr) should be consistent with the basis of surveillance tests used to show compliance with leak rate technical specifications." The density used by the licensee in converting volumetric leak rates to mass leak rates is based upon RCS conditions, which is consistent with the plant design basis. The licensee used a RCS fluid density to convert the primary-to-secondary leakage from a volumetric flow rate to a mass flow rate, which is consistent with the RCS cooldown rate applied in the generation of the secondary steam releases. This methodology follows sound engineering principles and is therefore acceptable to the NRC staff.

RG 1.183, Appendix F, Regulatory Position 5.3, states that, "The primary to secondary leakage should be assumed to continue until the primary system pressure is less than the secondary system pressure, or until the temperature of the leakage is less than 100°C (212 °F). The release of radioactivity from the unaffected SGs should be assumed to continue until SDC is in operation and releases from the SGs have been terminated." The St. Lucie 2 CLB for the termination of the affected SG activity release states that the affected SG is isolated within 30 minutes by operator action however for the EPU analysis this time is assumed to be 45 minutes. Isolation of the affected SG terminates releases from the ruptured SG, while primary-to-secondary leakage continues to provide activity for release from the unaffected SG.

The licensee assumed that a portion of the primary-to-secondary ruptured tube flow or break flow through the SGTR will flash to vapor based on the thermodynamic conditions in the RCS and the secondary system. For the unaffected SG used for plant cooldown, the licensee assumed that flashing would occur immediately following the reactor trip when tube uncovery is postulated. The licensee credited operator action to restore water level above the top of the tubes in the unaffected SG within a conservative time of one hour following a reactor trip. The licensee assumed that primary-to-secondary leakage would mix with the secondary water without flashing during periods of total tube submergence.

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 ruptured SG by the break flow. A portion of the break flow is assumed to flash to steam because of the higher enthalpy in the RCS relative to the secondary system. The licensee assumed that the flashed portion of the break flow will ascend through bulk water of the SG, enter the steam space of the affected generator, and be immediately available for release to the environment with no credit taken for scrubbing. Although RG 1.183 allows the use of the methodologies described in NUREG-0409 to determine the amount of scrubbing credit applied to the flashed portion of the break flow, the licensee did not credit scrubbing of the activity in the break flow in the ruptured SG.

For the SGTR event, after the affected SG isolation time point at T = 45 minutes, cooldown was continued until the RCS temperature reached a temperature of 212 °F. The licensee analyzed various cooldown rates and determined that the limiting release and dose consequence for this event would be produced using a cooldown rate of 20 °F per hour. The licensee calculated the total mass of steam released for various time periods during the plant cooldown. These masses, which were also used for non-SGTR events, were converted to average steam release rates for the following time periods:

- Event start to reactor trip (driven by mass release, no cooldown rate incorporated in the analysis)
- Reactor trip to 45 minutes, (driven by mass release, no cooldown rate incorporated in the analysis)
- 45 minutes to 2 hours, cooldown rate assumed: 100 °F per hour from HZP to 410 °F;
- 2 hours to 8 hours, cooldown rate assumed: approximately 20 °F per hour from 410 °F to residual heat removal (RHR) entry at 300 °F;
- 8 hours until the RCS temperature reaches 212 °F, cooldown rate assumed: approximately 20 °F per hour, 212 °F reached at 12.4 hours.

The SGTR dose analysis conservatively continued the intact SG primary to secondary leakage until the 12.4-hour time of termination of all releases.

During the first 0.0789 hours (284 seconds) of the event, prior to the reactor trip and the assumed concurrent LOOP, the licensee assumed that all of the SG flow is routed to the condenser. After 284 seconds, the condenser is no longer available due to the assumed LOOP.

The iodine and other non-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 partition coefficient (PC).

In accordance with applicable regulatory guidance, the licensee assumed a partition coefficient of 100 for iodine. The licensee assumed that the retention of particulate radionuclides in the SGs is limited by the moisture carryover from the SGs. The licensee assumed the same partition coefficient of 100, as used for iodine, for other particulate radionuclides. This assumption is consistent with the SG carryover rate of less than 1 percent.

In accordance with RG 1.183, Appendix E, Regulatory Position 5.6, the licensee evaluated the potential for SG tube bundle uncovery and determined that tube bundle uncovery is postulated to occur in the intact SG for up to 1 hour following a reactor trip for St. Lucie 2. During this period, the licensee assumed that the fraction of primary-to secondary leakage which flashes to vapor would rise through the bulk water of the SG into the steam space and be immediately released to the environment or the containment with no mitigation. The licensee determined the flashing fraction based on the thermodynamic conditions in the reactor and secondary coolant. The licensee assumed that the leakage which does not flash would mix with the bulk water in the SG.

2.9.2.4.2.3 CR Ventilation Assumptions for the SGTR

In order to evaluate the CR habitability for the postulated design basis SGTR, the licensee assumed three modes of operation for the CR ventilation system. During the normal mode of operation prior to CR isolation, there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively assumed to be 1000 cfm with an additional assumed unfiltered inleakage of 395 cfm. After the radiation monitors activate the emergency signal, both the north and south CR intakes are closed simultaneously. For the SGTR event, the licensee conservatively assumed that the CR isolation signal would be delayed until the release from the ADVs is initiated at 284 seconds. The licensee included an additional 30-second delay to account for the diesel generator start time, fan start, and damper actuation time. Therefore, for the SGTR analysis, the licensee assumed that CR isolation would occur 314 seconds after initiation of the postulated SGTR event. After isolation, the air flow distribution consists of 0 cfm of outside makeup flow, an assumed 395 cfm of unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

After 90 minutes from the onset of the accident, operator action is credited to open the more favorable CR air intake based on the output of the radiation monitors, maintaining positive pressure and initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, an assumed 395 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day accident evaluation period. The licensee assumed CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide. The CR parameters used in the AST analyses are shown in Table 4 of this SE.

2.9.2.4.3 Conclusion

The licensee evaluated the radiological consequences resulting from the postulated SGTR accident and concluded that the radiological consequences at the EAB, LPZ, and CR comply with the reference values and CR dose criterion provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review has found that the licensee used analyses, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 8 and the licensee's calculated dose results are given in Table 1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a design basis SGTR will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

2.9.2.5 RCP Shaft Seizure (Locked Rotor) Accident

2.9.2.5.1 Description of Event

Section 15.3.4 of the FSAR for St. Lucie 2 describes the locked rotor accident as an event in which the instantaneous seizure of a single RCP shaft occurs due to mechanical failure. The principal purpose of the RCP is to provide forced coolant flow through the core of the reactor. As a result of the mechanical failure, flow through the affected primary-to-secondary loop is rapidly reduced; ultimately, causing a three-pump system of reactor coolant flow through the core versus a four-pump system. The postulated sequence of events following a locked rotor accident is a reactor trip due to the low coolant flow rate, stored heat transferred to the primary coolant, rapid temperature increase in primary RCS, probable fuel damage due to a decrease of initial DNB margin, and SG tube leakage due to a significant pressure differential between the primary and secondary systems. Fission products from the damaged fuel in the St. Lucie 2 reactor core are assumed to mix instantaneously and homogeneously in the primary coolant. Primary coolant activity transfers to the secondary system via SG tube leakage. Primary coolant activity from SG tube leakage together with secondary activity is postulated to be released to the environment via the ADVs.

The licensee evaluated the locked rotor accident using the accident source term pursuant to guidance provided in RG 1.183, Appendix G. The licensee followed the regulatory positions noted in RG 1.183 to define the assumptions, parameters, and inputs used in calculating new values for the dose assessment of the postulated locked rotor accident.

2.9.2.5.2 Analysis Parameters and Assumptions

2.9.2.5.2.1 Locked Rotor Accident Source Term

For the EPU analysis, the licensee assumed that 19.7 percent of fuel assemblies that will experience DNB as a result of the locked rotor accident. The licensee incorporated the release fractions from Appendix G of RG 1.183 with an increase of 0.922 percent to account for high burnup fuel and a radial peaking factor of 1.65. In accordance with RG 1.183, Appendix G, the licensee assumed that all activity released from the breached fuel assemblies mixes both instantaneously and homogeneously throughout the primary coolant system. This activity is assumed to be released to the secondary system via SG tube leakage.

In accordance with RG 1.183, Appendix G, Regulatory Position 4, the licensee assumed that the chemical form of radioiodine released from the breached fuel assemblies consists of 95 percent CsI, 4.85 percent elemental iodine, and 0.15 percent organic iodide. The licensee also assumed that the chemical form of radioiodine released from the SGs to the environmental atmosphere consists of 97 percent elemental iodine and 3 percent organic iodide. This speciation is applicable to both the iodine released as a result of fuel damage and the iodine released from the pre-accident equilibrium iodine concentrations in the RCS and in the secondary coolant system. Additionally, the licensee accounted for the TS limited RCS and secondary activity in the calculations.

2.9.2.5.2.2 Transport

Pursuant to guidance provided in RG 1.183, Appendix G, the licensee analyzed the primary-to-secondary release path, with subsequent secondary release to the atmosphere via steaming from the ADVs without scrubbing. The released activity consists of the RCS TS equilibrium activity in addition to activity released from the breached fuel. The licensee assumed that the release of noble gases occurs without mitigation or reduction. The licensee used ground-level mode for the secondary release scenario of the locked rotor accident.

St. Lucie 2 consists of a two-loop RCS with two SGs. This results in four cold legs (i.e., two per SG) and four RCPs (i.e., one per SG cold leg). The activity released from the primary RCS to the secondary RCS is assumed to occur at a leak rate of 0.25 gpm per SG for a total of 0.50 gpm. This leakage rate was converted from a volumetric flow rate to a mass flow rate using the RCS fluid density based on a RCS cooldown rate of 100 °F per hour until the RCS temperature reaches 410 °F. The licensee provided additional information describing the basis for the assumed cooldown rates as they pertained to secondary side releases analyzed for the EPU. These cooldown rates are described in the transport section for the SGTR accident and are applicable to other non-SGTR accidents involving secondary side releases as a result of steaming to achieve plant cooldown.

In accordance with RG 1.183, if the temperature of the leakage exceeds 212 °F, the fraction of total iodine in the liquid that becomes airborne should be assumed equal to the fraction of the leakage that flashes to vapor. For the locked rotor accident analysis, the licensee assumed that 6 percent of the primary-to-secondary leakage will flash to steam during the assumed 1-hour period of tube uncovery.

Consistent with Regulatory Positions 5.5.1, 5.5.2, and 5.5.3 of RG 1.183, Appendix E, the licensee assumed that all of the primary-to-secondary leakage that does not flash mixes with the bulk water in the SGs. Additionally, in agreement with Regulatory Position 5.5.4, the licensee assumed that the radioactivity in the bulk water of both SGs becomes vapor at a rate that is a function of the steaming rate and the partition coefficient of 100 for iodine and other particulate radionuclides.

2.9.2.5.2.3 CR Ventilation Assumptions for the Locked Rotor Accident

In order to evaluate the CR habitability for the postulated design basis locked rotor accident, the licensee assumed three modes of operation for the CR. During normal mode of operation, there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively assumed to be 1000 cfm. After the radiation monitors activate the emergency signal, both north and south CR intakes are closed simultaneously. This occurs approximately 30 seconds into the postulated locked rotor accident. Accordingly, the air flow distribution during this post CR isolation mode consists of 0 cfm of outside makeup flow, 395 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow. After 90 minutes from the onset of the accident, operator action is credited to open the more favorable CR air intake based on the output of the radiation monitors, maintaining a positive pressure by initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, 395 cfm of assumed unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day accident analysis period. The licensee considered CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide.

2.9.2.5.3 Conclusion

The licensee evaluated the radiological consequences resulting from a postulated locked rotor accident at St. Lucie 2 and concluded that the radiological consequences at the EAB, outer boundary of the LPZ, and CR are within the reference values and CR dose criterion provided in 10 CFR 50.67 and accident specific dose guidelines specified in SRP 15.0.1. The staff's review has found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the staff are presented in Table 9 and the licensee's calculated dose results are given in Table 1. The staff finds that the doses estimated by the licensee for the St. Lucie 2 locked rotor accident will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

2.9.2.6 CEA Ejection Accident

2.9.2.6.1 Description of Event

Section 15.4.5 of the FSAR for St. Lucie 2 describes the CEA ejection accident as the mechanical failure of a CEA and drive shaft resulting in a rapid withdrawal of a single CEA from the reactor core. This uncontrolled ejection of a CEA is caused by a sudden circumferential break of either the CEDM pressure housing or the CEDM nozzle of the RV head. As a result, the pressure of the RCS acts to fully eject a CEA. The primary consequence of the described mechanical failure is a rapid reactivity insertion together with an adverse core power distribution (leading to a reactor trip and possible fuel rod damage. The licensee evaluated two independent release paths in the event of a CEA accident. The first release path assumes an instantaneous and homogeneous release of fission products from the damaged fuel in the reactor core to the containment atmosphere with successive release to the environment via containment leakage. The second release pathway assumes that all of the activity that is released from the damaged fuel is fully dispersed in the primary coolant and subsequently released to the secondary system via SG tube leakage. Activity is subsequently released from the secondary side to the environment via steaming from the ADVs.

The licensee evaluated the CEA event using the accident source term pursuant to guidance provided in RG 1.183, Appendix H. The licensee followed the regulatory positions noted in RG 1.183 to define the assumptions, parameters, and inputs used in calculating the dose assessment of the CEA accident.

2.9.2.6.2 Analysis Parameters and Assumptions

2.9.2.6.2.1 CEA Ejection Accident Source Term

For the purpose of this EPU analysis, the licensee assumed in both release scenarios that 9.5 percent of the fuel rods experience DNB and 0.5 percent of the fuel will experience FCM as a result of the CEA ejection from the reactor core. The licensee incorporated the release fractions from Appendix H of RG 1.183 with an increase of 0.922 percent to account for high burnup fuel and a radial peaking factor of 1.65. In deriving the source term for the CEA event, the licensee made assumptions consistent with Regulatory Position 1 of RG 1.183, Appendix H. Per this guidance, the licensee assumed the following conditions for the two release paths analyzed in the provided AST analysis:

> For the containment leakage release pathway, it is assumed that in the event of a CEA accident, 100 percent of the noble gases and 25 percent of the iodine contained in the assumed fraction of melted fuel are available for release via containment leakage. In addition, the release from the breached fuel is based on the estimate of the number of fuel rods breached and the assumption that 10 percent of the core inventory of the noble gases and iodines resides in the fuel gap. All of the activity released as a result of clad damage and core centerline melting is assumed to be released both instantaneously and homogeneously throughout the containment atmosphere.
>
> For the secondary system release pathway, it is assumed that in the event of a CEA, accident, 100 percent of the noble gases and 50 percent of the iodine contained in the assumed fraction of melted fuel are released to the RCS. In addition, the release from the breached fuel is based on the estimate of the number of fuel rods breached and the assumption that 10 percent of the core inventory of the noble gases and iodines resides in the fuel gap. All of the activity released as a result of clad damage and core centerline melting is assumed to be released both instantaneously and homogeneously throughout the primary coolant system and to be available for release to the secondary system via SG tube leakage.

In accordance with RG 1.183, Appendix H, Regulatory Position 4, the licensee assumed that the chemical form of radioiodine released to the containment atmosphere consists of 95 percent CsI, 4.85 percent elemental iodine, and 0.15 percent organic iodide. The licensee credits effective controls to limit the pH in the containment sump to 7.0 or higher. In agreement with Regulatory Position 5 of RG 1.183, Appendix H, the licensee assumed that the chemical form of radioiodine released from the SGs to the environment consists of 97 percent elemental iodine and 3 percent organic iodide. Additionally, the licensee accounted for the TS limited RCS and secondary system activity in the calculations.

2.9.2.6.2.2 Transport

Pursuant to guidance provided in RG 1.183, Appendix H, the licensee analyzed two release cases. The first case is based on the assumption that all of the fission products released from the damaged fuel in the reactor core are instantaneously and homogeneously mixed throughout the atmosphere of the containment. The licensee analyzed releases from the containment to the environment that are filtered via the SBVS and the released activity that bypasses the SBVS. The SBVS is assumed to remove 99 percent of the particulate activity and 95 percent of both the elemental iodine and organic iodide activity. The licensee assumed 9.6 percent of the activity leaked from the containment will bypass the SBVS filters in the CEA accident analysis.

The second case assumes that all of the fission products released from the damaged fuel in the reactor core are completely dissolved in the primary coolant system and are transferred to the secondary system via SG tube leakage. The activity in the secondary system is subsequently released to the environment via the ADVs without credit for SG scrubbing.

The licensee utilized the plant stack as the point of release for the containment scenario crediting SBVS filtration. This release was considered as a ground-level release per guidance provided in RG 1.145. A ground-level release mode was also used for the containment releases which bypass the SBVS and for the secondary release scenario.

2.9.2.6.2.3 Transport from Containment

For containment releases of the CEA accident, the licensee assumed that all activity from the breached fuel would release to and mix instantaneously and homogeneously in the containment volume. As specified in TS 3.6.1.1 limit, this activity was modeled to leak from the containment to the environment at an initial rate of 0.50 weight percent per day for the first 24 hours, followed by a rate of 0.25 weight percent per day for the remaining 29 days of the 30-day CEA accident analysis period. This assumption is consistent with Regulatory Position 6.2 of RG 1.183, Appendix H.

The licensee credited natural deposition of the released activity inside the containment. This credit was applied to the radionuclides released using a removal coefficient of 0.10 per hour for aerosols and 2.89 per hour for elemental iodine. No credit was applied to the natural deposition of organic iodide or for the removal of activity via CSs.

2.9.2.6.2.4 Transport from the Secondary System

For secondary releases of the CEA accident, the licensee assumed that all activity from the breached and melted fuel would release to and completely mix in the primary coolant system. Subsequently, the released activity is assumed to transfer to the secondary coolant system as a result of SG tube leakage. Releases to the environment occur as a result of steaming via the ADVs. The release of noble gases is assumed to occur without mitigation or reduction. The activity released from the primary-to-secondary system is assumed to occur at a leak rate of 0.25 gpm per SG for a total of 0.50 gpm. This leakage rate was converted from a volumetric flow rate to a mass flow rate using the RCS fluid density. The 0.50 gpm total primary-to-secondary leakage rate is assumed to continue until the SG is fully isolated. The time needed to achieve these conditions is assumed to be 12.4 hours. The licensee provided additional information describing the basis for the assumed cooldown rates as they pertained to secondary side releases analyzed for the EPU. These cooldown rates are described in the transport section for the SGTR accident and are applicable to other non-SGTR accidents involving secondary side releases as a result of steaming to achieve plant cooldown.

If the temperature of the leakage exceeds 212 °F, the fraction of total iodine in the liquid that becomes airborne should be assumed equal to the fraction of the leakage that flashes to vapor. The licensee has determined that the tube bundle in the intact SGs may become uncovered following a reactor trip and that a portion of the primary-to-secondary leakage will flash to steam while the tube bundle is uncovered. For the EPU CEA analysis, the licensee conservatively assumed that 6 percent of the primary-to-secondary leakage will flash to steam for a 1-hour period of tube uncovery.

Consistent with Regulatory Positions 5.5.1, 5.5.2, and 5.5.3 of RG 1.183, Appendix E, the licensee assumed that all of the primary-to-secondary leakage that does not flash mixes with the bulk water in the SGs. Additionally, in agreement with Regulatory Position 5.5.4 of this guidance, it is assumed that the radioactivity in the bulk water of both SGs becomes vapor at a rate that is a function of the steaming rate and the partition coefficient of 100 for iodine and other particulate radionuclides.

2.9.2.6.2.5 CR Ventilation Assumptions for the CEA Ejection Accident

In order to evaluate the CR habitability for the postulated design basis CEA ejection accident, the licensee assumed three modes of operation for the CR. During normal mode of operation (i.e., prior to CR isolation), there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively assumed to be 1000 cfm. After the radiation monitors activate the emergency signal, both north and south CR intakes are closed simultaneously. This occurs approximately 30 seconds into the postulated CEA accident. Accordingly, the air flow distribution during this post CR isolation mode consists of 0 cfm of outside makeup flow, 395 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow. After 90 minutes from the onset of the accident, operator action is credited to open the more favorable CR air intake based on the output of the radiation monitors, maintaining a positive pressure by initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, 395 cfm of assumed unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day accident analysis period. The licensee considered CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide.

2.9.2.6.3 Conclusion

The licensee evaluated the radiological consequences resulting from a postulated CEA accident at St. Lucie 2 and concluded that the radiological consequences at the EAB, outer boundary of the LPZ, and CR are within the reference values and the CR dose criterion provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP 15.0.1. The staff's review has found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the staff are presented in Table 10 and the licensee's calculated dose results are given in Table 1. The staff finds that the doses estimated by the licensee for the St. Lucie 2 CEA ejection accident will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

2.9.2.7 FWLB

2.9.2.7.1 Description of Event

The steam and water release from a postulated FW line break results in a loss of secondary coolant which may result in a reactor system cool-down by excessive energy discharge through the break or a reactor system heat-up from the loss of reactor system heat sink. A major FW line rupture is defined as a FW line break large enough to prevent the addition of sufficient FW to the SGs to maintain shell side fluid inventory in the SGs. If the break is postulated in the FW line between the isolation valves and the SG, fluid from the SG also is discharged from the break.

The licensee included the rupture of a main FW system pipe during plant operation as a part of the CLB AST evaluation and has updated the analysis to account for EPU conditions. The licensee assumed that the rupture results in the rapid reduction of the secondary water inventory of the affected SG causing a partial loss of secondary heat sink, thereby allowing the heat-up of the RCS. The FWLB is assumed to be located outside of containment resulting in a blowdown of the affected SG to atmosphere from the most limiting release location. The licensee evaluated this event assuming that a LOOP occurs at the time of the trip. Plant cooldown is achieved via the remaining unaffected SG. No fuel failures are postulated to occur as a result of this event.

Neither RG 1.183, nor SRP 15.0.1, includes the FWLB event as a DBA. Therefore, the licensee followed the methods employed in SRP, Section 15.8.2, "Feedwater System Pipe Breaks Inside and Outside Containment (PWR)," with appropriate modifications to maintain consistency with the assumptions in RG 1.183. The licensee used the most restrictive acceptance criteria from SRP 15.0.1, Table 1 and RG 1.183, Table 6, for application in the FWLB event. The approach taken by the licensee to evaluate the FWLB, using the applicable guidance from SRP, Section 15.8.2, and using the most restrictive acceptance criteria for any of the DBAs considered, is conservative, and therefore, acceptable to the NRC staff.

2.9.2.7.2 Analysis Parameters and Assumptions

2.9.2.7.2.1 FWLB Source term

The licensee assumed the initial RCS activity to be at the TS limit of 1.0 μCi/gm DEI and 518.9 μCi/gm DE Xe-133. The licensee assumed the initial SG secondary side activity to be at the TS 3.7.1.4 limit of 0.1 μCi/gm DEI. The FWLB analysis does not include a coolant spike.

2.9.2.7.2.2 Transport

The licensee's analysis assumes that the entire fluid inventory from the faulted SG is immediately released to the environment. The secondary coolant iodine concentration is assumed to be the maximum value of 0.1 μCi/gm DEI permitted by TS. Additional activity due to primary-to-secondary leakage into the faulted SG is also assumed to be released directly to the environment. Primary-to-secondary leakage is assumed to continue until the affected SG is completely isolated at 12.4 hours. Primary-to-secondary tube leakage is also postulated to occur in the unaffected SG. The licensee assumed that this activity is diluted by the contents of the SG and released via steaming from the ADVs, along with the initial iodine activity of unaffected SGs. All releases from the unaffected SG continue until the RCS is cooled to 212 °F. To evaluate the secondary side releases, the licensee used assumptions consistent with the Locked Rotor accident described earlier in this SE.

2.9.2.7.2.3 CR Ventilation Assumptions for the FWLB

In order to evaluate the CR habitability for the postulated design basis FWLB, the licensee assumed three modes of operation for the control room ventilation system. During the normal mode of operation prior to CR isolation, there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively assumed to be 1000 cfm. After the radiation monitors activate the emergency signal, both the north and south CR intakes are closed simultaneously. This occurs approximately 30 seconds into the postulated FWLB event. Accordingly, the air flow distribution during this post CR isolation mode consists of 0 cfm of outside makeup flow, 395 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow. After 90 minutes from the onset of the accident, operator action is credited to open the more favorable CR air intake based on the output of the radiation monitors, maintaining positive pressure and initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, an assumed 395 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day accident evaluation period. The licensee assumed CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide.

2.9.2.7.3 Conclusion

The licensee evaluated the radiological consequences resulting from the postulated FWLB accident and concluded that the radiological consequences at the EAB, LPZ, and CR comply with the reference values provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review has found that the licensee used analysis, assumptions, and inputs consistent with the most applicable regulatory guidance identified in Section 2.0 of this SE. In the absence of directly applicable guidance, the licensee used conservative assumptions to evaluate this event which are found to be acceptable to the NRC staff. The assumptions found acceptable to the NRC staff are presented in Table 11 and the licensee's calculated dose results are given in Table 1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a design basis FWLB will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

2.9.2.8 Letdown Line Rupture

2.9.2.8.1 Description of Event

This event is analyzed as a rupture of a primary coolant letdown line outside of containment. In accordance with the assumptions of FSAR Section 15.6.2, the dose assessment for this event is based on a double ended rupture of the letdown line in the auxiliary building outside of containment with a direct release to the environment via the plant stack. The licensee evaluated additional releases occurring as a result of secondary side steam relief following the turbine trip and subsequent plant cooldown.

Neither RG 1.183, nor SRP 15.0.1, includes the Letdown Line Rupture event as a DBA. Therefore, the licensee followed the methods employed in SRP, Section 15.6.2, "Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment," with appropriate modifications to maintain consistency with the assumptions in RG 1.183. The licensee used the most restrictive acceptance criteria from SRP 15.0.1, Table 1 and RG 1.183, Table 6, for application in the Letdown Line Rupture event. The approach taken by the licensee, to evaluate the Letdown Line Rupture, using the applicable guidance from SRP, Section 15.6.2, and using the most restrictive acceptance criteria for any of the DBAs considered, is conservative, and therefore, acceptable to the NRC staff.

2.9.2.8.2 Analysis Parameters and Assumptions

2.9.2.8.2.1 Letdown Line Rupture Source Term

In accordance with SRP 15.6.2, the licensee's analysis assumed an accident-generated or concurrent iodine spike. The RCS activity is initially assumed to be 1.0 μCi/gm DEI as allowed by TS 3.4.8. Iodine is released from the fuel into the RCS at a rate of 500 times the iodine equilibrium release rate for a period of 8 hours.

2.9.2.8.2.2 Transport

The licensee modeled the Letdown Line Rupture flow rate over 1800 seconds with a flashing fraction of 25.9 percent as computed using the RG 1.1 83 guidance from Regulatory Position 5.4 of Appendix A for ECCS leakage. All of the activity in the flashed fluid is assumed to be released directly to the environment. The licensee included the dose consequence of the release of additional activity, based on the proposed primary-to-secondary leakage limits, being released via steaming from the ADVs until the RCS is cooled to 212 °F. To evaluate the secondary side releases, the licensee used assumptions consistent with the Locked Rotor accident described previously in this SE.

2.9.2.8.2.3 CR Ventilation Assumptions for the Letdown Line Rupture

In order to evaluate the CR habitability for the postulated design basis Letdown Line Rupture, the licensee assumed three modes of operation for the CR ventilation system. The licensee used the same CR ventilation assumptions for the Letdown Line Rupture evaluation as was used in the MSLB evaluation described previously in this SE.

2.9.2.8.3 Conclusion

The licensee evaluated the radiological consequences resulting from the postulated Letdown Line Rupture accident and concluded that the radiological consequences at the EAB, LPZ, and CR comply with the reference values and the CR dose criterion provided in 10 CFR 50.67 and the most restrictive accident specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review has found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The licensee's assumptions are presented in Table 12 and the licensee's calculated dose results are given in Table 1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a design basis Letdown Line Rupture will comply with the requirements of 10 CFR 50.67 and the most restrictive dose guidelines of RG 1.183, and are therefore acceptable.

Conclusion

The NRC staff finds that the licensee used analysis methods and assumptions consistent with the conservative regulatory requirements and guidance identified in Section 2.9.2.1 of this SE. The NRC staff compared the doses at the EPU power level estimated by the licensee to the applicable dose guidelines identified in Section 2.9.2.1. The NRC staff finds that the licensee's estimates of the EAB, LPZ, and CR doses will comply with these guidelines. Therefore, the NRC staff finds with reasonable assurance that St. Lucie 2, as modified by this EPU license amendment, will continue to provide sufficient safety margins with adequate defense-in-depth to address unanticipated events and to compensate for uncertainties in accident progression and analysis assumptions and parameters. Therefore, the proposed EPU license amendment is acceptable with respect to the radiological consequences of DBAs.

Table 1
St. Lucie 2 Radiological Consequences Expressed as TEDE [(1)]
(rem)

DBAs	EAB [(2)]	LPZ [(3)]	CR[(4)]
LOCA	1.3E+00	2.7E+00	4.6E+00
MSLB – Outside containment (1.2% DNB)	2.7E−01	7.6E−01	4.4E+00
MSLB – Outside containment (0.29% FCM)	3.0E−01	8.1E−01	4.5E+00
MSLB – Inside containment (21% DNB)	4.1E−01	8.8E−01	4.5E+00
MSLB – Inside containment (4.5% FCM)	6.4E−01	1.2E+00	4.5E+00
SGTR Pre-accident spike	3.8E−01	3.7E−01	4.1E+00
Dose acceptance criteria	2.5E+01	2.5E+01	5.0E+00
SGTR Concurrent iodine spike	1.8E−01	1.8E−01	1.5E+00
Locked Rotor Accident (19.7% DNB)	3.7E−01	9.2E−01	4.4E+00
FWLB	1.5E−02	1.9E−02	6.3E−01
Letdown Line Rupture	3.2E−01	3.1E−01	2.8E+00
Dose acceptance criteria	2.5E+00	2.5E+00	5.0E+00
FHA – Containment	6.0E−01	5.8E−01	1.3E+00
FHA – FHB	6.0E−01	5.8E−01	3.0E+00
CEA Ejection Containment Release[(5)] (9.5% DNB, 0.5% FCM)	2.9E−01	5.7E−01	2.9E+00
CEA Ejection Secondary Side Release [(5)] (9.5% DNB, 0.5% FCM)	3.1E−01	7.3E−01	3.1E+00
Dose acceptance criteria	6.3E+00	6.3E+00	5.0E+00

(1) Total effective dose equivalent
(2) Exclusion area boundary - worst 2-hour dose
(3) Low population zone - Integrated 30 day dose
(4) CR - Integrated 30 day dose - assumed unfiltered inleakage of 395 cfm
(5) Assumes 9.5% DNB and 0.5% FCM
Note: Licensee's dose results are expressed to a limit of two significant figures.

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St. Lucie 2
Control Room (CR) Atmospheric Dispersion Factors (χ/Q Values)

A. LOCA: Containment Leakage - SBVS and Containment Purge / H_2 Purge

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Stack Vent / North CR Intake*	2.39E-03	---	---	---	---
During CR Isolation	Stack Vent / Midpoint CR Intake*	3.96E-03	---	---	---	---
After Initiation of Filtered Make-up	Stack Vent / South CR Intake*	6.70E-04	4.58E-04	2.02E-04	1.40E-04	1.13E-04

* Credit for dilution was taken in this case.

B. LOCA: Containment Leakage –SBVS Bypass

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Closest FW Line Point / North CR Intake	7.29E-03	---	---	---	---
During CR Isolation	Closest FW Line Point / Midpoint CR Intake	3.33E-03	---	---	---	---
After Initiation of Filtered Make-up	Closest FW Line Point/ South CR Intake	1.95E-03	1.57E-03	6.56E-04	4.75E-04	3.99E-04

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St. Lucie 2
Control Room (CR) Atmospheric Dispersion Factors (χ/Q Values)

C. LOCA: Emergency Core Cooling System (ECCS) Leakage

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Aux. Bldg. Louver 2L-7B / North CR Intake	4.80E-03	---	---	---	---
During CR Isolation	Aux. Bldg. Louver 2L-7A / Midpoint CR Intake	5.06E-03	---	---	---	---
After Initiation of Filtered Make-up	Aux. Bldg. Louver 2L-7A / South CR Intake	4.32E-03	3.72E-03	1.64E-03	1.34E-03	1.07E-03

D. LOCA: RWT Backleakage

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	RWT / North CR Intake	1.37E-03	---	---	---	---
During CR Isolation	RWT / Midpoint CR Intake	1.34E-03	---	---	---	---
After Initiation of Filtered Make-up	RWT / South CR Intake	1.04E-03	8.49E-04	3.64E-04	2.73E-04	2.32E-04

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St. Lucie 2
Control Room (CR) Atmospheric Dispersion Factors (χ/Q Values)

E. Fuel Handling Accident (FHA): Containment Release

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m³)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Containment Main't Hatch / North CR Intake	1.90E-03	---	---	---	---
During CR Isolation	Containment Main't Hatch / Midpoint CR Intake	1.27E-03	---	---	---	---
After Initiation of Filtered Make-up	Containment Main't Hatch / South CR Intake	8.28E-04	6.57E-04	2.92E-04	1.93E-04	1.76E-04

F. Fuel Handling Accident (FHA): FHB Release

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m³)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	FHB Closest Wall Point / North CR Intake	4.92E-03	---	---	---	---
During CR Isolation	FHB Closest Wall Point / Midpoint CR Intake	3.29E-03	---	---	---	---
After Initiation of Filtered Make-up	FHB Closest Wall Point / South CR Intake	1.87E-03	1.36E-03	5.88E-04	4.00E-04	3.06E-04

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St. Lucie 2
Control Room (CR) Atmospheric Dispersion Factors (χ/Q Values)

G. MSLB: Outside Containment

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Closest ADV / North CR Intake	6.71E-03	---	---	---	---
During CR Isolation	Closest ADV / Midpoint CR Intake	3.13E-03	---	---	---	---
After Initiation of Filtered Make-up	Closest ADV / South CR Intake	1.89E-03	1.53E-03	6.02E-04	4.55E-04	3.89E-04

H. MSLB: Inside Containment – SBVS

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Stack Vent / North CR Intake*	2.39E-03	---	---	---	---
During CR Isolation	Stack Vent / Midpoint CR Intake*	3.96E-03	---	---	---	---
After Initiation of Filtered Make-up	Stack Vent / South CR Intake*	6.70E-04	4.58E-04	2.02E-04	1.40E-04	1.13E-04

* Credit for dilution was taken in this case.

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St. Lucie 2
Control Room (CR) Atmospheric Dispersion Factors (χ/Q Values)

I. MSLB: Inside Containment – SBVS Bypass

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Closest FW Line Point / North CR Intake	7.29E-03	---	---	---	---
During CR Isolation	Closest FW Line Point / Midpoint CR Intake	3.33E-03	---	---	---	---
After Initiation of Filtered Make-up	Closest FW Line Point/ South CR Intake	1.95E-03	1.57E-03	6.56E-04	4.75E-04	3.99E-04

J. SG Tube Rupture (SGTR)

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	**Prior to Turbine Trip** Steam Jet Air Ejector/ North CR Intake	3.02E-03	---	---	---	---
	After Turbine Trip Closest ADV / North CR Intake	6.71E-03	---	---	---	---
During CR Isolation	Closest ADV / Midpoint CR Intake	3.13E-03	---	---	---	---
After Initiation of Filtered Make-up	Closest ADV / South CR Intake	1.89E-03	1.53E-03	6.02E-04	4.55E-04	3.89E-04

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St. Lucie 2
Control Room (CR) Atmospheric Dispersion Factors (χ/Q Values)

K. Locked Rotor

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Closest ADV / North CR Intake	6.71E-03	---	---	---	---
During CR Isolation	Closest ADV / Midpoint CR Intake	3.13E-03	---	---	---	---
After Initiation of Filtered Make-up	Closest ADV / South CR Intake	1.89E-03	1.53E-03	6.02E-04	4.55E-04	3.89E-04

L. CEA Ejection: Secondary Release

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Closest ADV / North CR Intake	6.71E-03	---	---	---	---
During CR Isolation	Closest ADV / Midpoint CR Intake	3.13E-03	---	---	---	---
After Initiation of Filtered Make-up	Closest ADV / South CR Intake	1.89E-03	1.53E-03	6.02E-04	4.55E-04	3.89E-04

Table 2 (Page 7 of 9)

St. Lucie 2
Control Room (CR) Atmospheric Dispersion Factors (χ/Q Values)

M. CEA Ejection: Inside Containment Leakage - SBVS

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Stack Vent / North CR Intake*	2.39E-03	---	---	---	---
During CR Isolation	Stack Vent / Midpoint CR Intake*	3.96E-03	---	---	---	---
After Initiation of Filtered Make-up	Stack Vent / South CR Intake*	6.70E-04	4.58E-04	2.02E-04	1.40E-04	1.13E-04

* Credit for dilution was taken in this case.

N. CEA Ejection: Inside Containment Leakage - SBVS Bypass

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Closest FW Line Point / North CR Intake	7.29E-03	---	---	---	---
During CR Isolation	Closest FW Line Point / Midpoint CR Intake	3.33E-03	---	---	---	---
After Initiation of Filtered Make-up	Closest FW Line Point/ South CR Intake	1.95E-03	1.57E-03	6.56E-04	4.75E-04	3.99E-04

Table 2 (Page 8 of 9)

St. Lucie 2
Control Room (CR) Atmospheric Dispersion Factors (χ/Q Values)

O. Letdown Line Break: Letdown Line Release

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Aux. Bldg. Louver 2L-7B / North CR Intake	4.80E-03	---	---	---	---
During CR Isolation	Aux. Bldg. Louver 2L-7A / Midpoint CR Intake	5.06E-03	---	---	---	---
After Initiation of Filtered Make-up	Aux. Bldg. Louver 2L-7A / South CR Intake	4.32E-03	3.72E-03	1.64E-03	1.34E-03	1.07E-03

P. Letdown Line Break: Secondary Release

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Closest ADV / North CR Intake	6.71E-03	---	---	---	---
During CR Isolation	Closest ADV / Midpoint CR Intake	3.13E-03	---	---	---	---
After Initiation of Filtered Make-up	Closest ADV / South CR Intake	1.89E-03	1.53E-03	6.02E-04	4.55E-04	3.89E-04

Table 2 (Page 9 of 9)

St. Lucie 2
Control Room (CR) Atmospheric Dispersion Factors (χ/Q Values)

Q. <u>FW Line Break: Intact SG</u>

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Closest ADV / North CR Intake	6.71E-03	---	---	---	---
During CR Isolation	Closest ADV / Midpoint CR Intake	3.13E-03	---	---	---	---
After Initiation of Filtered Make-up	Closest ADV / South CR Intake	1.89E-03	1.53E-03	6.02E-04	4.55E-04	3.89E-04

R. <u>FW Line Break: Faulted SG</u>

Operation Mode	Release/ Receptor Pair	χ/Q Values (sec/m^3)				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
Prior to CR Isolation	Closest FW Line Point / North CR Intake	7.29E-03	---	---	---	---
During CR Isolation	Closest FW Line Point / Midpoint CR Intake	3.33E-03	---	---	---	---
After Initiation of Filtered Make-up	Closest FW Line Point/ South CR Intake	1.95E-03	1.57E-03	6.56E-04	4.75E-04	3.99E-04

Table 3

St. Lucie 2
Offsite Atmospheric Dispersion Factors (χ/Q Values)

Offsite Dose Location		χ/Q Values* (sec/m^3)				
		0 to 2 Hours	**0 to 8 Hours**	**8 to 24 Hours**	**24 to 96 Hours**	**96 to 720 Hours**
Ground Release	**EAB**	1.05E-04	5.98E-05	4.52E-05	2.46E-05	1.02E-05
	LPZ	1.01E-04	5.74E-05	4.32E-05	2.33E-05	9.62E-06

*Note that *all* releases are assumed to be ground-level pursuant to RG. 1.145. The 0-2 hour EAB χ/Q value was used throughout the entire design-basis accident (DBA).

Table 4
St. Lucie 2 Control Room Data and Assumptions and Direct Shine Results

Control Room Volume (Includes TSC)	97,215 ft^3
Normal Operation	
Filtered Make-up Flow Rate	0 cfm
Filtered Recirculation Flow Rate	0 cfm
Unfiltered Make-up Flow Rate	1000 cfm
Assumed unfiltered Inleakage	395 cfm
Emergency Operation	
Isolation Mode:	
Filtered Make-up Flow Rate	0 cfm
Filtered Recirculation Flow Rate	1760 cfm(1)
Unfiltered Make-up Flow Rate	0 cfm
Assumed unfiltered Inleakage	395 cfm
Filtered Make-up Mode:	
Filtered Make-up Flow Rate	504 cfm(1)
Filtered Recirculation Flow Rate	1256 cfm(1)
Unfiltered Make-up Flow Rate	0 cfm
Assumed unfiltered Inleakage	395 cfm
Filter Efficiencies	
Particulates	99%
Elemental iodine	95%
Organic iodide	95%
CR operator breathing rate	
0 - 720 hours	3.5E−04 m^3/sec
CR occupancy factors	
0 - 24 hours	1.0
24 - 96 hours	0.6
96 - 720 hours	0.4
LOCA CR Direct Shine Dose	
Containment	0.029 rem
Filters	0.033 rem
External Cloud	0.083 rem
Total	**0.15 rem**

1. Control room emergency ventilation flow rates conservatively consider over/under frequency/voltage of the EDGs, as well as tolerance in the control room ventilation flow rate test acceptance criteria.

Table 5 (Page 1 of 3)
St. Lucie 2 Data and Assumptions for the LOCA

Core Power level	3030 MWt (~3020 +0.3%)	
Core Average Fuel Burnup	49,000 MWD/MTU	
Fuel Enrichment	1.5 – 5.0 weight percent (w/o)	
Initial RCS Equilibrium Activity in coolant blowdown	1.0 µCi/gm DEI 518.9 µCi/gm DE Xe-133	
Containment or Hydrogen purge release	2500 cfm	
Duration of Hydrogen purge release	30 seconds	
Primary containment leak rate		
0 - 24 hours	0.5% (by weight/day)	
24 - 720 hours	0.25% (by weight/day)	
Elemental iodine wall deposition coefficient (0-720 hours)	2.89 hr^{-1}	
Particulate natural deposition removal coefficient	Unsprayed	Sprayed region
0 - 8 hours	0.1 hr^{-1}	0 hr^{-1}
8 - 720 hours	0.1 hr^{-1}	0.1 hr^{-1}
Primary containment volume sprayed region	2,125,000 ft^3	
Primary containment volume unsprayed region	375,000 ft^3	
Flow rate between sprayed and unsprayed regions	12,500 cfm	
Spray Initiation time	80 seconds (0.0222 hours)	
Spray termination time	8 hours	
Elemental iodine spray removal coefficients		
0.0222 – 3.07 hours	20 hr^{-1}	
3.07 - 720 hours	0 hr^{-1}	
Particulate spray removal coefficients		
0.0222 – 2.643 hours	6.52 hr^{-1}	
2.643 - 8 hours	0.65 hr^{-1}	
8 - 720 hours	0 hr^{-1}	
Time of ECCS Recirculation	22.3 minutes	
Volume of water in containment sump (minimum)	57,683 ft^3	
ECCS Leakage to RAB (2 times allowed limit)	1.08 gph	
ECCS Flashing fraction		
Calculated	5.7%	
Used for dose determination	10%	
Chemical form of released iodine from ECCS leakage		
Particulate	0%	
Elemental	97%	
Organic iodide	3%	
ECCS area filter efficiencies		
Elemental	95%	
Organic iodide	95%	
Particulate	99%	

Table 5 (Page 2 of 3)
St. Lucie 2 Data and Assumptions for the LOCA

Sump volume at time of recirculation	57,683 ft^3
Initial RWT liquid inventory	65,350 gallons
ECCS leakage into RWT (2 times allowed value)	2 gpm
Flashing fraction for leakage into RWT	0 %
Release from RWT vapor space to environment	0.98 cfm

Time dependent RWT pH values

Selected times in hours	RWT pH
0.00	4.500
10.0	4.508
25.0	4.519
100.0	4.573
720.00	4.864

Time dependent RWT iodine concentration (gm-atom/liter)

Selected times in hours	Total Iodine	Elemental Iodine
0.00	0.000E+00	0.000E+00
10.0	1.248E−06	1.623E−08
25.00	3.107E−06	9.046E−08
100.0	1.111E−05	7.948E−07
720.00	4.088E−05	3.462E−06

RWT liquid temperature

Time in hours	Temperature (°F)
0.00 – 720.0	104.5

Time dependent RWT elemental iodine fraction

Selected times in hours	Elemental iodine fraction
0.00	0.000E+00
10.0	2.601E−02
25.0	5.822E−02
100.0	1.431E−01
720.00	1.694E−01

RWT partition coefficient (PC)

Time in hours	Elemental iodine PC
0.00 – 720.0	41.88

Table 5 (Page 3 of 3)
St. Lucie 2 Data and Assumptions for the LOCA

LOCA Release Rate from Sump to RWT Vapor Space

Time (hours)	Adjusted Iodine Release Rate (cfm)
0.0	0.0
0.37	5.485E−07
10.0	5.524E−06
25.0	3.235E−05
75.0	1.104E−04
125.0	2.026E−04
200.0	3.278E−04
300.0	4.659E−04
450.0	5.694E−04
600.0	6.223E−04

Secondary containment filter efficiency	
Particulate	99%
Elemental iodine	95%
Organic iodide	95%
Secondary containment drawdown time	310 seconds
Secondary containment bypass fraction	9.6%
Containment purge filtration efficiency	0%

Transport assumptions

Secondary containment prior to drawdown	Nearest containment penetration to CR
Secondary containment after drawdown	Plant stack
Secondary containment bypass leakage	Nearest containment penetration to CR
ECCS leakage	ECCS exhaust louver
RWT backleakage	RWT
Containment purge	Plant stack

Control Room Ventilation System

Time of automatic CR Isolation	30 seconds
Time of manual CR intake opening	1.5 hrs

Table 6
St. Lucie 2 Data and Assumptions for the FHA

Core thermal power level	3030 MWt (~3020 + 0.3%)
Core average fuel burnup	49,000 MWD/MTU
Discharged fuel assembly burnup	45,000 – 62,000 MWD/MTU
Fuel enrichment	1.5 – 5.0 w/o
Maximum radial peaking factor	1.65
Number of fuel assemblies in the core	217
Number of fuel assemblies damaged	1
Minimum post shutdown fuel handling time (decay time)	72 hours
High burnup fuel adjustment factor	2.0
Minimum pool water depth	23 feet
Fuel clad damage gap release fractions (2 times RG 1.183, Table 3)	
I-131	16%
Remainder of halogens	10%
Kr-85	20%
Remainder of noble gases	10%
Alkali metals	24% (remains in pool water)
Pool DF	
Noble gases and organic iodide	1
Aerosols	Infinite
Elemental iodine (23 ft of water cover)	285
Overall iodine (23 ft of water cover)	200 (effective DF)
Chemical form of iodine in pool	
Elemental iodine	99.85%
Organic iodide	0.15%
Chemical form of iodine above pool surface	
Elemental iodine	70%
Organic iodide	30%
Duration of release to the environment	2 hour release
Control room ventilation assumptions	
Isolation time	30 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	395 cfm

Table 7 (Page 1 of 2)
St. Lucie 2 Data and Assumptions for the MSLB Accident

Core Power level	3030 MWt (~3020 + 0.3%)
Core Average Fuel Burnup	49,000 MWD/MTU
Fuel Enrichment	1.5 – 5.0 w/o
Maximum radial peaking factor	1.65
Percent DNB for MSLB outside containment	1.2%
Percent DNB for MSLB inside containment	21%
Percent FCM for MSLB outside containment	0.29%
Percent FCM for MSLB inside containment	4.5%
Initial RCS Equilibrium Activity	1.0 μCi/gm DEI
	518.9 μCi/gm DE Xe-133
Secondary coolant iodine activity	0.1 μCi/gm DEI
High burnup fuel adjustment factor	1.00922
Primary to secondary leak rates	0.25 gpm per SG
Time to terminate SG tube leakage	12.4 hours
RCS mass	420,090 lbm (minimum)
SG secondary side mass assumptions	
Intact SG	121,970.5 lbm (minimum)
Faulted SG	219,009 lbm (maximum)
Time to reach 212 ˚F terminating steam release	12.4 hours
Intact SG steam release rate in lbm/min for time interval in hours	
0.00	9087.1
0.50	5124.4
2.00	2690.3
8.00	2611.7
9.00	2478.3
10.0	2393.3
11.0	2301.7
12.0	2213.3
12.4 - 720	0
SG secondary side iodine partition coefficients	
Intact SG	100
Faulted SG	1(none)
Chemical form of iodine released from the secondary side	
Particulate	0%
Elemental iodine	97%
Organic iodide	3%

Table 7 (Page 2 of 2)
St. Lucie 2 Data and Assumptions for the MSLB Accident

Credit for scrubbing within the SG bulk water	None
Intact SG tube uncovery following reactor trip	
Time until tube recovery	1 hour
Flashing fraction	6 %
Containment volume	2.50E+06 ft^3
Containment leakage rate	
0 to 24 hours	0.5% (by weight)/day
24 – 720 hours	0.25% (by weight)/day
Credit for CSs	None
Containment natural deposition coefficients	
Aerosols	0.1 hr^{-1}
Elemental iodine	2.89 hr^{-1}
Organic iodide	None
Secondary containment filter efficiency	
Particulate	99%
Elemental iodine	95%
Organic iodide	95%
Secondary containment drawdown time	310 seconds
Secondary containment bypass fraction	9.6%
Control room ventilation assumptions	
Isolation time	30 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	395 cfm

	MSLB SG Tube Leakage (lbm/min)	
Time (hours)	Intact SG	Faulted SG
0.00 – 0.50	1.58	2.00
0.50 – 1.00	1.67	2.00
1.00 – 1.50	1.75	2.00
1.50 – 2.00	1.83	2.00
2.00 – 4.00	1.86	2.00
4.00 – 6.00	1.90	2.00
6.00 – 9.00	1.94	2.00
9.00 – 11.00	1.97	2.00
11.00 – 12.40	2.00	2.00
12.40 - 720	0	0

Table 8 (Page 1 of 2)
St. Lucie 2 Data and Assumptions for the SGTR Accident

Core power level	3030 MWt (~3020 + 0.3%)
Initial RCS equilibrium activity	1.0 µCi/gm DEI
	518.9 µCi/gm DE Xe-133
Initial secondary side equilibrium activity	0.1 µCi/gm DEI
Initial maximum RCS equilibrium activity	1.0 µCi/gm DEI
Maximum pre-accident spike iodine concentration	60 µCi/gm DEI
Accident initiated iodine spike appearance rate	335 times equilibrium rate
Duration of accident initiated spike	8 hours
Break flow flashing fraction	
Prior to reactor trip	15.5%
Following reactor trip	7.5%
Time to terminate break flow	45 minutes
Primary to secondary SG tube leakage rate	0.25 gpm per SG
Time to terminate SG tube leakage	12.4 hours
Time to recover intact SG tubes	1 hour
SG secondary side iodine partition coefficients	
Flashed tube flow	None
Non-flashed tube flow	100
Time to reach 212 ˚F and terminate steam release	12.4 hours
RCS mass Pre-accident iodine spike	420,090 lbm
RCS mass Concurrent iodine spike	386,354 lbm
Secondary coolant system mass	
Minimum for SG tube leakage	121,970.5 lbm per SG
Maximum for secondary side release	219,009 lbm per SG

SGTR Break Flow and Steam Releases in lbm/min

			Steam Release to Atmosphere	
Time (hr)	Event Description	Break flow	Ruptured SG	Intact SG
0	SGTR	3993.0	122,133.8	121,521.1
0.0789	Rx Trip	2277.3	3658.1	3397.4
0.75	Ruptured SG Isolated	0.10	0.0	5028.0
1.25	Intact SG Re-covered	0.0	0.0	5028.0
2.0		0.0	0.0	2698.9
8.0		0.0	0.0	2626.7
9.0		0.0	0.0	2491.7
10.0		0.0	0.0	2406.7
11.0		0.0	0.0	2313.3
12.0		0.0	0.0	2223.3
12.4	Termination of releases	0.0	0.0	0

Table 8 (Page 2 of 2)
St. Lucie 2 Data and Assumptions for the SGTR Accident

SGTR Iodine Equilibrium Appearance Assumptions	
Maximum Letdown Flow	150 gpm at 120°F, 650 psig
Maximum Identified RCS Leakage	10 gpm
Maximum Unidentified RCS Leakage	1 gpm
RCS Mass	386,354 lbm
Isotope	Total Removal Constant
I-131	0.003430
I-132	0.008393
I-133	0.003925
I-134	0.016548
I-135	0.005117

RCS Iodine Inventory (Ci) for 8-hr concurrent spike with an appearance rate factor of 335

Isotope	Appearance rate (Ci/min)	8 hour total (Ci)
I-131	169.6	81,430
I-132	83.2	39,950
I-133	200.8	96,380
I-134	75.1	36,030
I-135	118.2	56,720

RCS Iodine concentrations for SGTR pre-existing spike of 60 µCi/gm DEI

I-131	50.6
I-132	10.1
I-133	52.3
I-134	4.6
I-135	23.6

SG secondary side iodine partition coefficients

Flashed tube flow	None
Non-flashed tube flow	100

Chemical form of iodine released from SGs

Particulate	0%
Elemental iodine	97%
Organic iodide	3%

Control room ventilation assumptions

Isolation time (total)	314 seconds
Start of release from ADVs	284 seconds
Delay for DG start, fan start and dampers	30 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	395 cfm

Table 9
St. Lucie 2 Data and Assumptions for the Locked Rotor Accident

Core Power level	3030 MWt (3020 + 0.3%)
Core Average Fuel Burnup	49,000 MWD/MTU
Fuel Enrichment	1.5 – 5.0 weight percent (w/o)
Maximum radial peaking factor	1.65
Percent of fuel rods in DNB	19.7%
High burnup fuel adjustment factor	1.00922
Initial RCS equilibrium activity	1.0 μCi/gm DEI
	518.9 μCi/gm DE Xe-133
Initial secondary side equilibrium activity	0.1 μCi/gm DEI
Total primary to secondary leak rate	0.5 gpm
Time to terminate SG tube leakage	12.4 hours
Time to recover SG tubes following Rx trip	1 hour
Flashing fraction	6%
Time to reach 212 ˚F terminating steam release	12.4 hours
RCS mass – minimum used to maximize dose	420,090 lbm
Secondary coolant system mass	
Minimum for SG tube leakage	121,970.5 lbm per SG
SG secondary side iodine partition coefficients	
Flashed tube flow	1(none)
Non-flashed tube flow	100

Locked rotor accident steam release rates (lbm/min)		Locked rotor accident total SG Leakage (lbm/min)	
Time (Hours)	Steam Release Rate	**Time (Hours)**	Total SG Leakage
0.00 – 0.5	11473.7	**0.00 – 0.5**	3.15
0.5 – 2.0	5124.4	0.5 – 1.00	3.34
2.0 – 8.0	2690.3	1.00 – 1.50	3.50
8.0 – 9.0	2611.7	1.50 – 2.00	3.65
9.0 – 10.0	2478.3	2.00 – 4.00	3.71
10.0 – 11.0	2393.3	4.00 – 6.00	3.80
11.0 – 12.0	2301.7	6.00 – 9.00	3.89
12.0 – 12.4	2213.3	9.00 – 11.00	3.96
12.4 - 720	0.0	11.00 – 12.40	4.00
		12.40 – 720.0	0.00

Control room ventilation assumptions	
Isolation time	30 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	395 cfm

Table 10 (Page 1 of 2)
St. Lucie 2 Data and Assumptions for the CEA Ejection Accident

Core Power level	3030 MWt (3020 + 0.3%)
Core Average Fuel Burnup	49,000 MWD/MTU
Fuel Enrichment	1.5 – 5.0 weight percent (w/o)
Maximum radial peaking factor	1.65
Percent of fuel rods in DNB	9.5%
Percent of fuel rods with FCM	0.5%
Initial RCS equilibrium activity	1.0 µCi/gm DEI
	518.9 µCi/gm DE Xe-133
Initial secondary side equilibrium activity	0.1 µCi/gm DEI
High burnup fuel adjustment factor	1.00922
Total primary to secondary leak rate	0.5 gpm
Time to terminate SG tube leakage	12.4 hours
Time to recover SG tubes following reactor trip	1 hour
Flashing fraction	6%
SG secondary side iodine partition coefficients	
Flashed tube flow	1(none)
Non-flashed tube flow	100
Time to reach 212 ˚F terminating steam release	12.4 hours
RCS mass – minimum used to maximize dose	420,090 lbm
Secondary coolant system mass	
Minimum for SG tube leakage	121,970.5 lbm per SG
Chemical form of iodine released to containment	
Particulate	95%
Elemental iodine	4.85%
Organic iodide	0.15%
Chemical form of iodine released from SGs	
Particulate	0%
Elemental iodine	97%
Organic iodide	3%
Control room ventilation assumptions	
Isolation time	30 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	395 cfm

Table 10 (Page 2 of 2)
St. Lucie 2 Data and Assumptions for the CEA Ejection Accident

Containment volume	2.5E+06 ft^3
Containment leakage rate	
0 to 24 hours	0.5% (by weight)/day
24 – 720 hours	0.25% (by weight)/day
Secondary containment filter efficiency	
Particulate	99%
Elemental iodine	95%
Organic iodide	95%
Secondary containment drawdown time	310 seconds
Secondary containment bypass fraction	9.6%
Containment natural deposition coefficients	
Aerosols	0.1 hr^{-1}
Elemental iodine	2.89 hr^{-1}
Organic iodide	None
Credit for CSs	None

CEA steam release rates and SG Tube leakage (lbm/min)

Time (Hours)	Steam Release Rate	Time (Hours)	Total SG Leakage
0.00 – 0.5	11473.7	0.00 – 0.5	3.15
0.5 – 2.0	5124.4	0.5 – 1.00	3.34
2.0 – 8.0	2690.3	1.00 – 1.50	3.50
8.0 – 9.0	2611.7	1.50 – 2.00	3.65
9.0 – 10.0	2478.3	2.00 – 4.00	3.71
10.0 – 11.0	2393.3	4.00 – 6.00	3.80
11.0 – 12.0	2301.7	6.00 – 9.00	3.89
12.0 – 12.4	2213.3	9.00 – 11.00	3.96
12.4 - 720	0.0	11.00 – 12.40	4.00
		12.40 – 720.0	0.00

Table 11
St. Lucie 2 Data and Assumptions for the FWLB

Core Power level	3030 MWt (3020 + 0.3%)
Initial RCS equilibrium activity	1.0 µCi/gm DEI
	518.9 µCi/gm DE Xe-133
Initial secondary side equilibrium activity	0.1 µCi/gm DEI
SG tube leakage	0.25 gpm per SG
Time to terminate SG steam release	12.4 hours
Time to terminate SG tube leakage	12.4 hours
Time to recover SG tubes following reactor trip	1 hour
Flashing fraction	6%
SG secondary side iodine partition coefficients	
Unaffected SG	100
Faulted SG	None
Maximum secondary side mass for secondary release	219,009 lbm (Faulted SG)
Minimum secondary side mass for steam release	121,970.5 lbm (Intact SG)
Control room ventilation assumptions	
Isolation time	30 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	395 cfm

FWLB steam release rates and SG Tube leakage (lbm/min)

Steam Release Rate		SG Tube Leakage		
Time (Hours)	lbm/min	Time (Hours)	Intact SG	Faulted SG
0.00 – 0.5	9087.1	0.00 – 0.5	1.58	2.00
0.5 – 2.0	5124.4	0.5 – 1.00	1.67	2.00
2.0 – 8.0	2690.3	1.00 – 1.50	1.75	2.00
8.0 – 9.0	2611.7	1.50 – 2.00	1.83	2.00
9.0 – 10.0	2478.3	2.00 – 4.00	1.86	2.00
10.0 – 11.0	2393.3	4.00 – 6.00	1.90	2.00
11.0 – 12.0	2301.7	6.00 – 9.00	1.94	2.00
12.0 – 12.4	2213.3	9.00 – 11.00	1.97	2.00
12.4 - 720	0.0	11.00 – 12.40	2.00	2.00
		12.40 – 720.0	0.00	0.00

Table 12 (Page 1 of 2)
St. Lucie 2 Data and Assumptions for the Letdown Line Rupture

Core Power level	3030 MWt (3020 + 0.3%)
Initial RCS equilibrium activity	1.0 μCi/gm DEI
	518.9 μCi/gm DE Xe-133
Initial secondary side equilibrium activity	0.1 μCi/gm DEI
SG tube leakage	0.25 gpm per SG
Accident initiated iodine spike appearance rate	500 times equilibrium rate
Iodine Equilibrium Appearance Assumptions	Same as SGTR
Duration of accident initiated spike	8 hours
Time to terminate SG steam release	12.4 hours
Time to terminate SG tube leakage	12.4 hours
Time to recover SG tubes following reactor trip	1 hour
Flashing fraction	6%
Broken line flashing fraction	25.9%
Time to terminate break flow	1800 seconds
RCS mass	386,354 lbm
Minimum secondary side mass for steam release	121,970.5 lbm (per SG)

Control room ventilation assumptions

Isolation time	30 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	395 cfm

Letdown Line Rupture Steam Release Rates and SG Tube Leakage (lbm/min)

Time (Hours)	Steam Release Rate
0.00 – 0.5	11473.7
0.5 – 2.0	5124.4
2.0 – 8.0	2690.3
8.0 – 9.0	2611.7
9.0 – 10.0	2478.3
10.0 – 11.0	2393.3
11.0 – 12.0	2301.7
12.0 – 12.4	2213.3
12.4 - 720	0.0

Time (Hours)	Total SG Leakage
0.00 – 0.5	3.15
0.5 – 1.00	3.34
1.00 – 1.50	3.50
1.50 – 2.00	3.65
2.00 – 4.00	3.71
4.00 – 6.00	3.80
6.00 – 9.00	3.89
9.00 – 11.00	3.96
11.00 – 12.40	4.00
12.40 – 720.0	0.00

Table 12 (Page 2 of 2)
St. Lucie 2 Data and Assumptions for the Letdown Line Rupture

RCS Iodine Inventory (Ci) for 8-hr concurrent spike with an appearance rate factor of 500

Isotope	Appearance rate (Ci/min)	8 hour total (Ci)
I-131	253.2	121,500
I-132	124.2	59,620
I-133	299.7	143,900
I-134	112.0	53,770
I-135	176.4	84,650

Letdown Line Break Flow (lbm/min)

Time (hours)	Total Break Flow	Flashed Break Flow
0 – 0.236	4329.23	1121.3
0.236 – 0.50	2082.3	539.3
0.50	0.0	0.0

2.9.3 Radiological Consequences of Gas Decay Tank Ruptures

Regulatory Evaluation

The license performed an analysis of the radiological consequences of the rupture of a waste gas decay tank (WGDT). The analysis was conducted to verify the adequacy of design and of operation of the GWMS with respect to the change in source term caused by EPU conditions. The NRC Staff reviewed the radiological consequences of the WGDT rupture to ensure compliance with:

- BTP 11-5, Rev. 3 from the SRP, insofar as it established specific analysis and acceptance criteria for licensee evaluations of this event.

- 10 CFR 50.67, insofar as it establishes requirements for AST licensed plants that radiological doses from postulated accidents to individuals offsite and control room operators will be below established guidelines.

Technical Evaluation

2.9.3.1 Description of Event

The licensee evaluated the WGDT rupture under EPU conditions assuming that a single WGDT fails catastrophically, instantaneously releasing the entire inventory of stored gaseous activity to the environment at ground level.

2.9.3.2 Acceptance Criteria

BTP 11-5 allows for a dose acceptance criterion of 2.5 rem TEDE for systems designed to withstand explosions and earthquakes. For systems not designed to withstand explosions and earthquakes, BTP 11-5 imposes a significantly lower acceptance criterion of 0.1 rem TEDE. As described in FSAR Section 11.3, the licensee's GWMS is designed to prevent an explosive gas mixture and the WGDTs are seismically designed. Notwithstanding the fact that the licensee's GWMS meets the criteria for the higher acceptance criterion, the licensee has chosen the more restrictive criterion of 0.1 rem to establish the proposed TS limit for the contents of the WGDTs. The offsite dose acceptance criterion for a WGDT rupture accident of 0.1 rem TEDE applies to receptors located at the EAB and the outer boundary of the LPZ. In accordance with 10 CFR 50.67, the licensee evaluated the WGDT rupture using a CR dose acceptance criterion of 5.0 rem TEDE.

2.9.3.3 Applicable Regulatory Guidance

The licensee analyzed the WGDT rupture accident using NRC guidance given in RIS 2006-04, "Experience with Implementation of Alternative Source Terms", regarding application of the AST to WGDT events. RIS 2006-04 guidance specifically endorses BTP 11-5, Rev. 3 from the SRP.

2.9.3.4 Source Term and Dose Models, Assumptions, and Parameters

In accordance with BTP 11-5 Position 1.B, "Source Term", the licensee developed the design basis source term based on an assumption that one percent of the operating fission product inventory in the core is released to the RCS. BTP 11-5 Position 1.B specifies that typical operation of equipment should be assumed to remove gases from the coolant, and to process and treat them. The licensee's design basis RCS inventory is based on an extended full power operation period with 1 percent failed fuel releasing fission product gases into the RCS.

The licensee conservatively assumed that the entire RCS noble gas inventory is instantaneously transferred into one WGDT following reactor shutdown. The WGDT rupture is modeled based on an assumption that the entire WGDT inventory of noble gases is released instantaneously to the environment at ground level with no credit for decay or for isolation of the release path.

The licensee modeled the CR using assumptions consistent with other design basis events even though filtration will have no impact on the WGDT noble gas source term. The licensee assumed that unfiltered CR inleakage continues at 460 cfm throughout the 30-day event and that normal CR ventilation mode unfiltered makeup air continues for 50 seconds, until CR isolation is assumed to occur. The licensee confirmed that the WGDT rupture will generate sufficient airborne activity to initiate automatic CR isolation well within the 50-second assumption. Consistent with other design bases events, the licensee assumed that after 1.5 hours CR operators identify the most favorable CR intake and implement pressurization mode through air make up and recirculation operations of the ventilation system. The licensee considered several different release points and CR intake locations to generate atmospheric dispersion factors (X/Qs) in order to bound all possible release-receptor pairs for both St. Lucie units.

2.9.3.5 Results

The licensee's calculated offsite radiological doses for the design basis WGDT rupture source term of 90,921 DE curies Xe-133 are approximately 50 percent of the BTP 11-5 specified limit of 0.1 rem TEDE and the calculated CR dose is less than 10 percent of the CR dose guideline of 5 rem TEDE as stated in of 10 CFR 50.67. In addition the licensee derived the proposed TS limit of 165,000 curies of DE Xe-133 by increasing the dose equivalent source term proportionately to yield a predicted EAB dose very close to the dose limit of 0.1 rem TEDE.

Conclusion

The licensee analyzed the radiological consequences of releases from an accidental WGDT rupture accounting for the effects of the proposed EPU. The licensee has determined that the calculated total effective dose equivalents at the EAB and the LPZ outer boundary from a postulated WGDT rupture are below the dose guidelines of BTP 11-5. In addition, the licensee has determined that the CR dose will continue to meet its CLB with respect to the dose criterion of 10 CFR 50.67. The NRC staff conducted a confirmatory calculation and determined that the licensee's TS limit is acceptable. The staff's review also found that the licensee used analyses, assumptions, and inputs consistent with applicable regulatory guidance identified in this SE. Therefore, based on consistency with applicable guidance and engineering judgment, the NRC staff finds the proposed EPU acceptable with respect to the radiological consequences of an accidental WGDT release.

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

Regulatory Evaluation

The NRC staff conducted its review in this area to ascertain what overall effects the proposed EPU will have on both occupational and public radiation doses and to determine that the licensee has taken the necessary steps to ensure that any dose increases will be maintained within applicable regulatory limits and ALARA. The NRC staff's review included an evaluation of any increases in radiation sources and how this may affect plant area dose rates, plant radiation zones, and plant area accessibility. The NRC staff evaluated how personnel doses needed to access plant vital areas following an accident are affected. The NRC staff also considered the effects of the proposed EPU on plant effluent levels and any effect this increase may have on radiation doses at the site boundary. The NRC's acceptance criteria for occupational and public radiation doses are based on 10 CFR Part 20, and 10 CFR Part 50, Appendix I. Specific review criteria are contained in SRP Sections 12.2, 12.3, 12.4, and 12.5, NUREG-0737, Item II.B.2, and other guidance provided in Matrix 10 of RS-001.

Technical Evaluation

Radiation Sources

The original plant shielding design for St. Lucie Unit 2 was based on a core power level of 2560 MWt with 1 percent fuel defects and a 1-year fuel-cycle length. In March 1985, NRC authorized an increase in plant output to 2700 MWt. Currently Unit 2 is operating at 2700 MWth with an 18 month fuel cycle. The licensee is proposing new core power level of 3020 MWt on an 18-month fuel cycle. This represents an approximate 11.85 percent increase in power level from the original licensed power. For purposes of evaluating the impact of the EPU, the licensee evaluated the EPU based on 3030 MWt to account for a 0.3 percent power uncertainty margin. This represents an approximate 12.2 percent increase in power level from the original licensed power. In general, the production of radiation and radioactive material (either fission or activation products) in the reactor core is directly dependent on the neutron flux and power level of the reactor. Therefore, an approximate 12.2 percent increase in power level is expected to result in a proportional increase in the direct (i.e. from the reactor fuel) and indirect (i.e., from the reactor coolant) radiation source terms.

The proposed EPU will require an increase in the nuclear fission rate which will lead to an increase in the nuclear flux in the reactor core. The increased flux will cause an increase in neutron activation products in the RCS, control rod assemblies, reactor internals, and the pressure vessel as well as an increase in the fission product inventory in the core and spent fuel. The increased flux will also result in an increase in neutron and gamma flux leakage out of the RV. The increased inventory of fission products in the core will increase the activity concentration in the reactor coolant due to fuel defects. In the event of primary-to-secondary leakage in the SGs, the activity concentration in the secondary system will also increase relative to pre-EPU conditions. The increase in radioactivity levels in the core and RCS will result in an increase in radiation levels in the containment building, RAB, and other locations subject to direct shine from radiation sources contained in these buildings.

Radiation Levels

As stated earlier, the approximate 12.2 percent increase in power level associated with the proposed EPU is expected to result in a proportional increase in the direct and indirect radiation source terms. The licensee has utilized scaling techniques to determine the impact of the EPU on plant radiation levels in the major plant areas affected by this proposed power increase. The licensee's evaluation takes credit for conservatism in existing shielding analyses, the TSs limits on reactor coolant activity, and the site's ALARA program to demonstrate continued adequacy of current plant shielding to ensure compliance with the occupational dose limits of 10 CFR Part 20. The NRC agrees with this approach.

The radiation dose rates near the RV are determined by the neutron and gamma leakage flux from the RV during operation and by the gamma fluxes in the core and the activation activities in the RV internals, pressure vessel, and primary system piping walls during shutdown. The primary purpose of the reinforced concrete primary shield wall surrounding the RV is to attenuate the neutron and gamma fluxes leaking out of the RV. The licensee estimates that the normal operation radiation levels near the RV will increase by a factor of approximately 12.2 percent due to the increased neutron and gamma flux leakage resulting from the proposed EPU. However, in performing new design calculations to support the proposed EPU, the licensee has determined that the combination of the following 3 items will offset the anticipated 12.2 percent increase in radiation levels:

1. the conservatism in the original analysis of the shielding design
2. the conservatism in the pre-EPU design basis source term used to establish the radiation zones
3. the more restrictive reactor coolant radionuclide concentrations required by the EPU and change to TS 3.4.8 which significantly reduces the design basis source term

The licensee has determined, by shielding calculations, that the current neutron and gamma leakage from the RV is significantly less than the leakage conservatively estimated in the original design basis calculations. The NRC concludes that although the neutron and gamma flux levels will increase by 12.2 percent as a result of the EPU, increases in radiation levels near the RV will not be substantially greater than the radiation levels previously estimated and approved in the original design basis analyses. As a result of a review of the information provided, which included a spot check of the equations and conservatisms, the NRC finds the proposed EPU will be acceptable with respect to dose rates near the RV.

The radiation dose rates in containment areas adjacent to the RCS during operation are determined primarily by the N-16 levels in the reactor coolant. The shutdown dose rates in these areas are determined primarily by the deposited corrosion product activity and the cobalt impurities in the RCS and the SG components. The licensee estimates that, following EPU, both the N-16 and corrosion product source terms will increase by approximately 12.2 percent, resulting in operating and shutdown radiation levels in these areas increasing by the same percentage. The primary function of the secondary shielding which surrounds the RCS and the SGs is to attenuate the radiation levels from the N-16 source to those areas of containment outside of this secondary shield. The licensee stated that the increase in radiation levels due to the EPU will not affect the plant radiation zoning. Based on a review of the information provided, the NRC concludes the increase in radiation levels will be small. Such small changes are not expected to impact plant radiation zoning, personnel doses, or transit times. As a result, the NRC agrees a 12.2 percent increase in radiation levels will be acceptable.

In most areas outside containment, the radiation sources are fission products and corrosion products in the primary coolant or down-stream sources originating from the primary coolant activity. The licensee estimates that, following EPU, both the fission products and the activated corrosion products will increase by approximately 12.2 percent, resulting in an approximate 12.2 percent increase in radiation levels in these areas. For example, the radiation levels in the auxiliary building near systems and components containing RCS fluids are expected to increase by approximately 12.2 percent. The radiation levels near the condensate polishing system may increase. The licensee indicates no additional personnel access controls will be required in this area other than continued use of existing plant ALARA procedures. The NRC finds a potential increase of 12.2 percent in dose rates in the area outside of containment will not affect the licensee's ability to comply with 10 CFR 20 limits. The NRC has reviewed the information provided and concludes the proposed EPU will result in acceptable dose rates in areas outside containment. Additionally, the NRC finds the anticipated increase in dose rates near the condensate polishers will have no significant impact on compliance with 10 CFR 20 limits since the current dose rates at the condensate polishers are so low (e.g., in the range of 0.1 mrem/hr or less).

As described above, the normal operation radiation levels in most of the plant area are expected to increase by approximately 12.2 percent. The licensee has stated that this expected increase in radiation levels will not affect radiation zoning, occupancy limits, or shielding requirements because of the conservatism in the licensee's shielding analyses and the TS limits on reactor coolant concentrations. The NRC finds that the licensee's established, NRC approved radiation protection program is sufficient to assure that all radiation areas are properly designated, posted, and controlled, in a timely manner, as required by 10 CFR Part 20 and TSs.

The licensee indicates the exposure to plant personnel and to the offsite public is also expected to increase approximately 12.2 percent. The NRC Occupational Exposure data base indicates that during the 3 years from 2008 to 2010, the annual collective dose at St. Lucie was greater than the national average for PWRs. The licensee estimates that the annual collective dose at St. Lucie will increase by approximately 12.2 percent as a result of implementing the proposed EPU. Assuming that the annual collective dose at St. Lucie does increase by approximately 12.2 percent following EPU, the resulting annual collective dose at St. Lucie should still be less than half the occupational dose of the NRC-licensed PWR reporting the highest 3-year average. These occupational doses are well within those allowed by 10 CFR 20. The licensee indicates doses to members of the public offsite, resulting from effluent releases, are also expected to increase by 12.2 percent. The NRC finds that effluents from St. Lucie are approximately one to two orders of magnitude below the 10 CFR Part 50 Appendix I design objectives, and are two to three orders of magnitude below the limits of 10 CFR 20. As a result, the NRC finds that an anticipated increase of 12.2 percent will not challenge the 10 CFR Part 50 design objectives or the 10 CFR 20 dose limits for members of the public, and the proposed EPU is acceptable from the perspective of exposure of plant personnel and the offsite public.

Compliance with Item II.B.2 ensures that operators can access and perform required duties and actions in designated vital areas. Item II.B.2 of NUREG 0737 requires licensees to demonstrate that during a DBA, access to areas of the plant needed to operate equipment vital to mitigating the consequences of that accident (vital areas), can be achieved within the dose criteria of GDC 19. GDC 19 requires that adequate radiation protection be provided such that the dose to personnel shall not exceed 5 rem whole body, or its equivalent, to any part of the body for the duration of the accident, or alternatively, not to exceed 5 rem TEDE for licensees that have adopted the alternate source term under 10 CFR 50.67. St. Lucie has been approved for use of alternate source terms at EPU power level for post-accident dose assessments associated with onsite locations that require continuous occupancy such as the CR, and the TSC. The licensee indicates the Unit 1 CR and the TSC share the same HVAC envelope and will meet the same radiological habitability criteria. The TSC is located within the Unit 1 CR envelope. The licensee's calculations indicate that the dose to the Unit 1 CR would be 4.97 rem TEDE or less when employing alternate source term and making changes consistent with EPU conditions. Licensee calculations also indicate the dose to the common TSC due to the Unit 2 EPU is bounded by the calculations for Unit 1 (i.e., will be less than 4.97 rem TEDE), which meets the 5 rem TEDE requirements of NUREG-0737, Item II.B.2. Since it meets the requirements, the NRC finds this acceptable.

In the amendment request, the licensee stated vital areas are addressed in FSAR Table 12.3A-7. Table 12.3A-7 indicates the control room is a vital area. The adequacy of the control room and TSC habitability envelope to meet the GDC 19 dose criteria (as required by NUREG-0737 II.B.2) is addressed in the Design Basis Consequence Analysis of this SE.

Public and Offsite Radiation Exposures

The liquid radioactive waste system is designed to operate such that the doses to members of the public in the unrestricted area are within the design objectives of 10 CFR Part 50, Appendix I. These design objectives have been incorporated into St. Lucie's TSs.

At the original rated power, the doses from radioactive liquid effluents were a small fraction of the TS limits. The licensee estimates that the radioactivity content of the liquid releases will increase by a maximum of 12.2 percent for tritium and long-lived radionuclides, with an expected increase of 12.3 percent for I-131 as a result of the EPU. The licensee evaluated historical liquid effluent data which indicated a 12.2 percent increase in effluent activity for tritium and long-lived nuclides—including a 12.3 percent increase for iodine—would still ensure compliance with the TSs limits. The NRC finds the information presented by the licensee is sufficient to conclude the licensee can meet the design objectives of 10 CFR Part 50 Appendix I. Additionally, the NRC staff evaluated liquid effluent data from Annual Radioactive Effluent Release Reports submitted by the licensee and found that the dose from liquid effluents was less than 1 percent of the 10 CFR Part 50 design objectives. As a result, NRC staff concludes a 12.2 percent increase in activity (or 12.3 percent increase for I-131) would allow the licensee to meet the design objectives in 10 CFR Part 50, Appendix I.

The gaseous radioactive waste system is designed to operate such that the doses to members of the public in the unrestricted area are within the design objectives of 10 CFR Part 50, Appendix I. These design objectives have been incorporated into St. Lucie's TSs.

At the original rated power, the doses from radioactive gaseous effluents were a small fraction of the TS limits. The licensee estimates that the radioactivity content of the gaseous releases of noble gases will increase by a maximum of 12.9 percent, with an expected increase of 13.2 percent for short-lived gaseous radionuclides, and an increase of 12.2 percent for tritium as a result of the EPU. The licensee indicates increases in iodines will be 12.2 percent in the reactor coolant and will increase 22.2 percent in secondary steam in the event of primary to secondary leakage. The increases from gaseous effluents are due to the large increase in moisture carryover as a result of the EPU. The licensee indicates that even though I-131 will increase by the largest fraction, it will not be the dose-controlling radionuclide from a dose perspective since tritium will continue to be the controlling nuclide. NRC staff reviewed gas release data from Annual Radioactive Effluent Release Reports submitted by the licensee and found that the dose from gaseous effluents was less than 1 percent of the 10 CFR Part 50 design objectives. The NRC has evaluated this information and agrees that moisture carryover will increase radionuclide transport but only during episodes of primary-to-secondary leakage. NRC review of St. Lucie gaseous radwaste historical data indicates a 12.2 percent to 13.2 percent increase in gaseous radwaste following EPU will still allow the licensee to meet the NRC design objectives in 10 CFR Part 50, Appendix I. Additionally, during times of primary-to-secondary leakage, the secondary system activity limits in TSs and the radioactive effluent control program will provide additional assurance that the projected doses from gaseous effluents following EPU will still be significantly below the 10 CFR Part 50, Appendix I design objectives.

The licensee estimates the activity contained in (and the dose rate from) the solid waste following EPU is estimated to be bounded by an increase of 14.2 percent, which is the product of the expected 12.2 percent increase normalized to a unit power capacity factor of 100 percent. The direct shine from solid radioactive waste stored onsite could affect the offsite radiation dose. 40 CFR Part 190 limits the annual whole body dose to an actual member of the public to 25 mrem to the whole body from all pathways (e.g., from liquid releases, gaseous releases, and direct radiation from the facility). The licensee evaluated the direct shine dose rates based on results of previous Annual Radioactive Effluent Release and those reports indicated a 14.2 percent increase in the direct shine dose rates from storage of solid radwaste would not challenge the 25 mrem whole body standard of 40 CFR 190. The NRC has reviewed this data and agrees with this assessment and concludes the proposed EPU will not affect compliance with 40 CFR 190. The licensee stated that the procedures and controls in the Offsite Dose Calculation Manual would monitor the direct shine component of the offsite dose and the licensee would limit the offsite dose to ensure continued compliance with the 40 CFR Part 190 dose limits through storage, and administrative controls. The NRC finds the licensee's estimate of an increase of 14.2 percent in solid waste volume/curies to be reasonable since the EPU is expected to result in an increase in liquid and gaseous waste generated by 12.2 percent. Furthermore, normalizing the value to 14.2 percent to adjust the solid waste generation to a 100 percent power capacity factor is a conservative assumption that provides a reasonable bounding estimate of increases in solid waste generation. The NRC has reviewed the information presented by the licensee in the licensing report, and the NRC has also reviewed previous Annual Radiological Environmental Operating Reports which indicate the total dose from liquid effluents, gaseous effluents and direct radiation is less than 2 mrem per year, and concludes a 14.2 percent increase in direct radiation will not challenge the 40 CFR 190 dose limits. The NRC staff concludes the licensee has provided sufficient information to demonstrate the expected increase in solid waste generation will allow the licensee to continue to comply with the dose limits of 40 CFR 190.

On the basis of information contained in the licensee's submittal regarding public and offsite radiation exposures, any increase in offsite doses due to EPU will be well within the TS dose limits and below the limits of 10 CFR Part 20, 40 CFR Part 190, and the Design Objectives of 10 CFR Part 50, Appendix I, during normal operations and AOOs.

Ensuring that Occupational and Public Radiation Exposures are ALARA

The Radiation Protection Program at St. Lucie ensures that internal and external radiation exposures to station personnel, contractor personnel, and the general population resulting from station operation will be within applicable limits and will be ALARA. Design features currently in place to support St. Lucie's commitment to ALARA exposures include shielding to reduce levels of radiation, ventilation arranged to control the flow of potentially contaminated air, an installed radiation monitoring system used to measure levels of radiation in potentially occupied areas and measure airborne radioactivity throughout the plant, and respiratory protection equipment which is used as prescribed by the Radiation Protection Program. Compliance with the requirements of the Offsite Dose Calculation Manual ensures that radioactive discharges and public exposures are ALARA. The design features currently in place at St. Lucie will be able to compensate for the anticipated increases in dose rates associated with the EPU. Therefore, the increased radiation sources resulting from this proposed EPU will not adversely impact the licensee's ability to maintain occupational and public radiation doses resulting from plant operation to within the applicable limits in 10 CFR Part 20, the Design Objectives of 10 CFR Part 50, Appendix I, and ALARA.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on radiation source terms and plant radiation levels. The NRC staff concludes that the licensee has taken the necessary steps to ensure that any increases in radiation doses will be maintained ALARA. The NRC staff further concludes that the proposed EPU meets the requirements of 10 CFR Part 20, and 10 CFR Part 50, Appendix I and meets the guidelines contained in Item II.B.2 of NUREG-0737. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to radiation protection and ensuring that occupational radiation exposures will be maintained ALARA.

2.11 Human Performance

2.11.1 Human Factors

Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The NRC staff's human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system changes made to implement the proposed EPU. The NRC staff's review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed EPU. The NRC's acceptance criteria for human factors are based on GDC 19, 10 CFR 50.120, 10 CFR Part 55, and the guidance in GL 82-33. Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0.

Technical Evaluation

The NRC staff has developed a standard set of topics for the human factors assessment of EPUs (i.e., RS-001, Review Standard for Extended Power Uprates, Section 3.2 for BWRs or Section 3.3 for PWRs, Insert 11 (ADAMS Accession No. ML033640024)). FPL has addressed these topics in its submittals. The following are FPL's description of these topics and the staff's evaluation.

Emergency and Abnormal Operating Procedures

This section includes a summary of the licensee's assessment of how the proposed EPU will change the plant emergency and abnormal operating procedures, and the staff's evaluation of that assessment.

FPL performed a review of the EOPs and abnormal operating procedures or off-normal operating procedures (ONPs), as they are called at the St Lucie 2, to identify any changes that are required to support the EPU project. In addition, FPL conducted a review of the operator actions and times credited in the plant's FSAR Chapter 15 safety analyses, to determine if there is any impact to those analyses as a result of EPU.

On the basis of the above reviews, the licensee concluded that the EPU will require revisions to EOPs and ONPs to address changes in a variety of setpoints, alarms, and physical plant changes that are needed to support the EPU. The most significant changes are listed below:

- Boric acid makeup tank requirements will change due to increased boron concentration requirements for EPU. The combination of volume and boron concentration changes will result in changes to the associated curves in various ONPs.

- The TS minimum required CST volume will not change for EPU, but the allocation of the contained volume will change. As a result, the CST level requirements will change for cooling down to SDC entry conditions.

- Various I&C modifications will affect the ONP load list. Procedure changes are required to include the new electrical loads.

- Main FW pump suction pressure alarm and automatic trip setpoints will change as a result of the replacement of the main FW pumps to support EPU.

- Turbine drain valves cycle on cross over steam pressure [from HP to low pressure turbines]. Due to changes in MWt power level and condenser backpressure values, this setpoint will change.

- The existing setpoint for loop ΔT will increase. This setpoint is used in conjunction with other indications, to assess the status of single phase liquid natural circulation flow in at least one RCS loop.

- The boric acid precipitation analysis determined that increases will be required to the minimum simultaneous hot leg and cold leg injection flow rates to preclude boric acid precipitation.

- The EOP and ONP safety injection delivery curves will require revision to reflect the HPSI accident analysis pressure reference point. The associated flow delivery curves will be revised consistent with the assumptions of the accident analysis.

- The time to boil will decrease as a result of the EPU. This is due to an increase in decay heat in the core following a trip from a higher RTP associated with the EPU.

- The RCS makeup flow for boiloff versus time after shutdown will increase as a result of the EPU. This is due to the increased decay heat in the core as a result of the higher RTP from the EPU and will decrease the time to boiling.

Affected procedures will be revised to reflect the above changes, and other more minor changes, such as insignificant setpoint changes, prior to start up after St Lucie 2, EPU implementation. The procedure development and revision processes used at St. Lucie, as described by the licensee, are comprehensive and rigorous, and include verification of technical accuracy and written correctness, as well as validation by means of simulation, walkdown, and operator tabletop discussions. Detailed information about the St Lucie change processes from the Human Factors perspective may be found in the following site procedures:

- Q1-5-PR-PSL-3, Verification Guide for Emergency Operating Procedures
- Q1-5-PR-PSL-4, Validation Guide for Emergency Operating Procedures
- Q1-5-PR-PSL-6, Requirements for Development and Revision of Emergency Operating Procedures [Procedures Generation Package (PGP)]
- ADM-09-02, EOP Plant-specific technical Guidelines
- ADM-11-09, Emergency and Off-normal Operating Procedures Writers' Guide

Based on these factors, the staff finds the FPL identification and resolution of EOP and AOP impact due to EPU acceptable.

Operator Actions Sensitive to Power Uprate

The licensee stated in its LAR that any new operator actions or changes in current operator actions needed as a result of the EPU will be addressed in accordance with plant procedures, which provide guidance to ensure that control room modifications conform to the human factors criteria established in NUREG-0700, as well as site-specific guidelines. These processes also ensure that each change is fully reviewed and approved by station and operations personnel prior to implementation. These licensee processes provide increased confidence that operator actions that are sensitive to power uprate will be of high quality regarding their human factors characteristics. Additionally, as described above in section 3.1, changes that involve EOPs are subjected to the verification and validation processes of the licensee's QA program.

The licensee reviewed operator actions in the FSAR Chapter 15 safety analyses for changes in the timing, sequence, or existence of credited EOP operator actions. The licensee identified the following changes:

- In the event of a total loss of FW (TLOFW); a new step sequence is being implemented for securing all four RCPs. A step to secure all four RCPs in a TLOFW is being moved to early in the postulated event to conserve SG inventory. Currently, two RCPs are tripped early in the event and the remaining two RCPs are secured later in the event.

- In the event of a SGTR; the current analysis requires isolation of the affected SG and opening of the atmospheric dump valve associated with the affected SG within 30 minutes. The EPU analysis supports a revised action time of 45 minutes.

The licensee stated that there are no operator workarounds being created by the EPU or that affect timely execution of EPU-related actions, and that there are no operator actions that are being automated or changed from automatic to manual, as a result of EPU.

The NRC concurs with the licensee's conclusion that the additions, deletions, and changes in the sequence or timing of operator actions sensitive to EPU are not significant in terms of overall mitigation strategy, and that the licensee's established change processes will assure that required revisions are technically adequate, correctly written, and within the abilities of St. Lucie 2operators to perform within the time constraints established by analyses.

Changes to Control Room Controls, Displays, and Alarms

This section includes the licensee's assessment of any changes that the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms, and the staff's evaluation of the licensee's assessment.

FPL stated in its LAR that changes to the St. Lucie 2 control room controls, displays, and alarms would not be extensive and will generally include calibration and/or rescaling of instrumentation loops. The licensee states that the following instrumentation is affected by EPU:

a. LEFM

   The Cameron LEFM CheckPlus™ system will be installed as part of the EPU to provide accurate determination of main FW flow. Top level LEFM output data (i.e., calculated FW flow, FW temperature, and system status) will be integrated into existing computer system secondary calorimetric displays and calorimetric power calculations to provide the primary operator interface. The LEFM system interface will include redundant touch screen displays. These displays will be located in the control room (behind the main control boards) and will support detailed investigation of LEFM system status and review of system diagnostic parameters.

b. The following instrument loops are affected by the EPU (calibration range, setpoint transmitter changes and/or scaling):

   - FW flow – The range of the various FW flow channels will be increased to accommodate the higher EPU flow rates. Associated indicators, recorders, computer points, and alarm setpoints will be rescaled to reflect the increased range.

   - Main steam flow – The range of the various main steam flow channels will be increased to accommodate the higher EPU flow rates. Associated indicators, recorders, computer points, and alarm setpoints will be rescaled to reflect the increased range.

- Turbine steam chest pressure –The HP turbine is being replaced and turbine steam chest pressure will change. Pressure sensing lines are being modified for the replacement turbine. Associated control systems [digital electro-hydraulic (DEH) and reactor regulating system] will be rescaled, as necessary.

- FW pump suction – Low suction pressure alarm and pump trip setpoints will be revised to reflect EPU operating conditions and new requirements for the replacement main FW pumps.

c. Annunciator Response Procedures Will Require Revision as a Result of Setpoint Changes

Annunciator response procedures will be revised as necessary to reflect new operating parameters and instrument channel rescaling as described above.

d. Plant Computer Setpoints Will Change

Plant computer setpoints will be revised as necessary to reflect new operating parameters and instrument channel rescaling as described above.

e. Changes to Controls and Control Systems

- FW Control System will be revised as follows:

  Range changes for main steam and FW flow, scaling changes to reflect replacement FW pump performance and FW control valve curves, and improvements to transition logic between main FW control valves and low power control valves to minimize loss of SG inventory following a turbine trip.

- SBCS will be revised as follows:

  Range changes for steam header pressure input signal, scaling changes for revised valve capacities, changes to the sequential valve position versus master controller demand to reflect linearization of valve trim, and changes to the quick open logic to improve system response during transition back to modulation control.

- Leading Edge Flow Meter will result in the following:

  The existing FW flow is measured using venturi DP signals as part of the distributed control system (DCS). To support EPU, the existing DCS is being modified to use newly installed LEFMs, which provide alternate FW flow inputs. The LEFM system status will be communicated via dedicated alarms and displays, and it will provide alarms for degraded and/or inoperable modes.

- Turbine Controls will be revised as follows:

  Turbine governor valve control will be changed from partial arc (sequential valve) to full arc (single valve), with other modes of operation (speed, MW, and turbine impulse pressure) remaining the same. As part of the turbine controls modification, the existing computer will be replaced with a more modern computer and operator interface panels will be replaced with dedicated touch-screen panels.

- MSR and FW Heater 5A/B Level Controls will be revised as follows:

  The existing pneumatic controls for MSR and high pressure FW heater 5 level controls will be replaced with electronic instruments. The existing backup level switch control functions will not be changing.

The above control room modifications have been or will be assessed for potential Human Factors Engineering (HFE) impact using plant administrative procedure NE-AA-205-1100, Design Change Packages and EC Form-250, Human Factors Engineering Checklist. Those modifications identified as having HFE impact will be further reviewed for compliance with NUREG-0700 and site-specific HFE guidance. Based on the licensee's use of accepted HFE standards and guidelines, the staff finds the licensee's approach to controlling HFE design changes to the St. Lucie 2 control room acceptable. Application of these administrative controls should result in effective and useable controls, displays, and alarms.

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 EPU and how the licensee will make the operators aware of the proposed SPDS changes.

In its LAR, FPL stated that no significant SPDS changes are anticipated as a result of the proposed EPU. Critical safety function status trees will be reviewed and revised as necessary for related changes to setpoints and decision points (e.g., normal core full power ΔT, and T_{hot} minus T_{cold}).

Any changes identified to the safety parameter display system will be captured through the normal update process, modification process, and interdepartmental reviews. Based on the administrative control processes in place at St. Lucie 2, the staff finds the proposed approach to changes in the design of SPDS acceptable.

Control Room Plant Reference Simulator and Operator Training

This section includes the review of changes to the operator training program and the plant referenced control room simulator resulting from the proposed EPU and the implementation schedule for making the changes.

FPL stated in its LAR that FPL will ensure that adequate training is provided prior to EPU implementation per its normal training program. The proposed training will focus on the TS changes, procedure changes and plant modifications, and will take place during the training cycle prior to the outage implementing the EPU modifications.

The operators will also be provided station modification review packages as well as classroom and simulator training where appropriate. Plant uprate analyses and modifications will be incorporated in the plant simulator software modeling. The physical changes to the control rooms as a result of EPU modifications, and setpoint and scaling changes will be incorporated in the simulator. These changes will be scheduled to allow training prior to EPU implementation. As a result, the operators will be able to demonstrate an understanding of the integrated plant response on the simulator prior to plant operation under uprated conditions. The staff finds these changes to the training program and the simulator to be acceptable in both content and schedule.

Conclusion

The NRC staff has reviewed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that the licensee has (1) appropriately accounted for the effects of the proposed EPU on the available time for operator actions and (2) taken appropriate actions to ensure that operator performance is not adversely affected by the proposed EPU. The NRC staff further concludes that the licensee will continue to meet the requirements of GDC 19, 10 CFR 50.120, and 10 CFR Part 55 following implementation of the proposed EPU. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the human factors aspects of the required system changes.

2.12 Power Ascension and Testing Plan

2.12.1 Approach to EPU Power Level and Test Plan

Regulatory Evaluation

The purpose of the EPU test program is to demonstrate that SSCs will perform satisfactorily inservice at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The NRC staff's review included an evaluation of: (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance; (2) transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level; and (3) the test program's conformance with applicable regulations.

The NRC's acceptance criteria for the proposed EPU test program are based, in part, on 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service; NRC RG 1.68, Appendix A, Section 5, "Power Ascension Tests," which describes tests that demonstrate that the facility operates in accordance with design both during normal steady-state conditions, and, to the extent practical, during and following AOOs; and specific review criteria contained in Section III, "Review Procedures," of SRP 14.2.1. Other guidance is also provided in Section 2 and Insert 12 for Section 3.3, "PWR Template Safety Evaluation" of RS-001, Revision 0.

Technical Evaluation

2.12.1.1 SRP 14.2.1, Section III.A, Comparison of Proposed EPU Test Program to the Initial Plant Test Program

Section 14.2.1 of the SRP specifies the guidance and acceptance criteria that the licensee should use to compare the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison should include: (1) all initial power-ascension tests performed at a power level of equal to or greater than 80-percent OLTP level; and (2) initial test program tests performed at lower power levels if the EPU would invalidate the test results. The licensee shall either repeat initial power-ascension tests within the scope of this comparison or adequately justify proposed test deviations. The following specific criteria should be identified in the EPU test program:

- All power-ascension tests initially performed at a power level of equal to or greater than 80-percent of the OLTP level,
- All initial test program tests performed at power levels lower than 80-percent of the OLTP level that would be invalidated by the EPU, and
- Differences between the proposed EPU power-ascension test program and the portions of the initial test program identified by the previous criteria.

The NRC staff reviewed EPU test plan information provided by the licensee to verify that the initial EPU application, including supplemental information, addressed the specific criteria for an adequate EPU test program as described above. The staff reviewed Attachment 5, "Licensing Report," of the LAR which discusses the analyses and evaluations performed to demonstrate that the proposed increase in power can be safely achieved with no adverse impact on the health and safety of the public. The staff also reviewed Licensing Report Table 2.12-3, "Post-Modification Testing," of Attachment 5 to the LAR, for a list of planned modifications necessary to support power operation at the proposed uprated core thermal power, and the associated post-modification testing planned for these modifications. The planned modifications listed in the table constitute planned actions on the part of the licensee and do not constitute regulatory commitments. The modifications will be implemented in accordance with the requirements of 10 CFR 50.59 and will provide functional and operational post modification testing for each modification to verify satisfactory installation and performance.

The staff also found that transient tests described in the initial startup test program were listed in Table 2.12-2, "Comparison of Proposed EPU Tests to Original Startup Tests," of Attachment 5. The Table provided a summary of the original startup testing performed in accordance with FSAR Sections 14.2.12.2-4, and also included the initial startup test objectives, a brief comparison with the proposed power ascension and testing plan (PATP), and a justification for not repeating certain of the original tests during the proposed EPU test plan. Table 2.12-1, "EPU Power Ascension Test Plan," of Attachment 5, provided a listing of power ascension startup tests to be performed at EPU power levels through 100-percent RTP of 3020 MWt. The licensee stated in the LAR that analyses were performed for EPU using the CENTS computer code for certain operating transients and that the results were used, in part, as the basis for the justification of the elimination of certain transient testing included in the original startup testing program.

FPL stated in the LAR that the EPU testing program will also draw on the results of the original startup and test program and applicable industry experience as a means of ensuring safe operation at the new core thermal power level. Comparisons will be made between pre-determined acceptance criteria and the data that will be gathered during the uprate testing to ensure that the results are reasonable. Additionally, FPL stated that St. Lucie 2 has significant operating experience at its current operating conditions such that system interactions are well known. FPL also stated that Arkansas Nuclear One, Unit 2 (ANO-2) and Waterford 3 have uprated to a core thermal power level that is nearly identical to that requested for

St. Lucie 2 (3026 MWt and 3020 MWt, respectively); and that both have operated successfully at the new power level for seven and four years, respectively. Both ANO-2 and Waterford 3 are CE-designed NSSS plants.

As stated in the LAR, the St. Lucie 2 PATP is primarily an initial power ascension test plan in which power will be increased in a slow and deliberate manner, stopping at pre-determined power plateaus for steady-state data gathering and formal parameter evaluation. The program consists of a combination of normal startup and surveillance testing, post-modification testing, and power ascension testing deemed necessary to support acceptance of the proposed EPU. At approximately 89-percent EPU power (2700 MWt), power will be slowly and deliberately increased through four additional test plateaus, and each differing by approximately 3 percent of the EPU RTP. Both dynamic performance during the ascension and steady-state performance for each test plateau will be monitored, documented and evaluated against predetermined acceptance criteria and expected values.

The staff concludes through comparison of the documents referenced above, including a review of the initial startup tests and planned EPU testing described in Attachment 5 to the LAR, the proposed power ascension test program conforms to the NRC's acceptance criteria of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," including specific review criteria contained in Section III.A. of SRP 14.2.1, and other staff guidance provided in RS-001. Therefore, the proposed power ascension and testing plan is acceptable.

2.12.1.2 SRP 14.2.1, Section III.B, Post Modification Testing Requirements for Functions Important to Safety Impacted by EPU-Related Plant Modifications

This Section of the SRP specifies the guidance and acceptance criteria, which the licensee should use to assess the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to an AOO. AOOs include those conditions of normal operation that are expected to occur one or more times during the life of the plant and include events such as LOOP, tripping of the main turbine generator set, and loss of power to all RCPs. The EPU test program should adequately demonstrate the performance of SSCs important to safety that meet all of the following criteria: (1) the performance of the SSC is impacted by EPU-related modifications; (2) the SSC is used to mitigate an AOO described in the plant-specific design basis; and, (3) involves the integrated response of multiple SSCs.

The staff reviewed Attachment 5 to the LAR which discusses the planned modifications scheduled to be performed prior to operation at EPU conditions. Modifications necessary to allow operation at EPU conditions are scheduled to be implemented during refueling outage SL2-20 (Spring 2012). A list of significant plant modifications planned to improve overall plant operating margin and support the proposed EPU is provided in Attachment 5, Table 2.12-3 "Post-Modification Testing." Some of the key modifications planned prior to operation at EPU conditions include, but are not limited to, upgrading condensate and FW system components; controls and instrumentation; main generator upgrade; main steam, FW and condensate systems instrumentation; and replacement of MFW pumps and heaters. Functional and operational post-modification testing will be performed for each modification to verify satisfactory installation and performance.

The NRC staff also reviewed the licensee's approach relative to assessing the aggregate impact of the proposed equipment modifications. In Section 2.12.1.2.6, "Transient Analytical Methodology," of the LAR, the licensee stated that analyses and evaluations had been performed for the Condition I, II, III, and IV operating transients to assess the aggregate impact of the equipment modifications and setpoint changes for EPU conditions. Condition I, II, III, and IV refers to the following four classifications of plant conditions established by ANS: normal operation and operational transients, incidents of moderate frequency, infrequent incidents, and limiting faults, respectively, in accordance with the anticipated frequencies of occurrence and potential radiological consequences. Analysis inputs and models were updated as appropriate to incorporate the EPU equipment modifications and setpoint changes as well as the EPU operating conditions. The licensee stated that in terms of transient response, the most significant hardware modifications are those for the SBCS and the FW system; and that the aggregate impact of the hardware changes on dynamic plant response is addressed through CENTS analyses for Condition I initiating events and Condition II trip tests.

The licensee stated that transient accident analyses evaluations were performed using the NRC-approved CENTS computer code acceptable for analyzing operational transients for CE-designed PWRs which include Waterford 3; San Onofre Nuclear Generating Station (SONGS), Units 2 and 3; ANO-2; and the Palo Verde Nuclear Generating Station (PVNGS), Units 1-3. The CENTS code is described in Westinghouse Owners Group Topical Report WCAP-15996-P-A, Revision 1, "Technical Description Manual for the CENTS Code," March 2005. The CENTS code was used for the analysis of design basis transients at EPU conditions and incorporated the applicable EPU equipment modifications and setpoint changes as well as the EPU operating conditions. The NSSS transients evaluated for EPU using the CENTS code are shown in Table 2.12-4 of LAR Attachment 5, and include reactor trip from 100-percent power and step load changes. The code has been used for many years for accident evaluations for safety analysis reports and for control system performance and has also been used for the Waterford 3 and ANO-2 EPU applications. As documented in the CENTS Topical Report CENPD-282-P-A, the NRC SE for the code concluded that CENTS is "acceptable for referencing in licensing actions with respect to the calculation of non-LOCA transient behavior in [PWRs]."

The NRC staff concludes that the licensee's proposed EPU PATP demonstrates that EPU related modifications will be adequately implemented. Specifically, the staff concludes that based on a review of the listing of completed and planned modifications, the proposed EPU test program should adequately demonstrate the performance of SSCs, and complies with the criteria established in Section III.B of SRP 14.2.1.

2.12.1.3 SRP 14.2.1, Section III.C, Use of Evaluation to Justify Elimination of Power-Ascension Tests

This Section of the SRP specifies the guidance and acceptance criteria the licensee should use to provide justification for a test program that does not include all of the power-ascension testing that would normally be performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in Section III.C.2. The proposed EPU test program shall be sufficient to demonstrate that SSCs will perform satisfactorily in service. The following factors should be considered, as applicable, when justifying elimination of power-ascension tests:

- Previous operating experience,
- Introduction of new T-H phenomena or identified system interactions,
- Facility conformance to limitations associated with analytical analysis methods,
- Plant staff familiarization with facility operation and trial use of operating and EOPs,
- Margin reduction in safety analysis results for AOOs,
- Guidance contained in vendor topical reports, and
- Risk implications.

The staff's review is intended to provide reasonable assurance that the performance of plant equipment important to safety that could be affected by integrated plant operation or transient conditions is adequately demonstrated prior to extended operation at the requested EPU power level. The staff recognized that the licensee may propose a test program that does not include all of the power-ascension testing referred to in Sections III.A and III.B of SRP 14.2.1 that would normally be performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in SRP Section III.C.2. If the licensee proposes to omit certain original startup tests from the EPU testing program based on favorable operating experience, the applicability of the operating experience to the specific plant must be demonstrated. Plant design details such as configuration, modifications, and relative changes in setpoints and parameters, equipment specifications, operating power level, test specifications and methods, engineering operating procedures, and adverse operating experience from previous EPUs, should be considered and addressed.

The EPU PATP is relied upon as a quality check to confirm that analyses and any modifications and adjustments that are necessary for proposed EPUs have been properly implemented, and to benchmark the analyses against the actual integrated performance of the plant. This is consistent with 10 CFR Part 50, Appendix B, which states that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate calculation methods, or by the performance of a suitable testing program; and requires that design changes be subject to design control measures commensurate with those applied to the original plant design, which includes power ascension testing. SRP 14.2.1 specifies that the EPU test program should include steady-state and transient performance testing sufficient to demonstrate that SSCs will perform satisfactorily at the requested power level and that EPU-related modifications have been properly implemented. The SRP provides guidance to the staff in assessing the adequacy of the licensee's evaluation of the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to AOOs.

The St. Lucie 2 EPU PATP is comprised of power ascension monitoring, post-modification testing and analytical evaluation with no large load transient testing planned as part of the EPU PATP. The PATP does not include all the power ascension testing that would typically be performed during initial startup of a new plant. The PATP is based, in part, on plant-specific experience, industry PWR EPU operating experience, St. Lucie 2 Startup Test Reports, outputs of various system and integrated plant analyses performed in support of the EPU, FSAR Chapter 14, and review of planned EPU modifications, which FPL has used in the formulation of expected system interactions, design of EPU modifications, determination of control system settings and setpoints, and development of post-modification and power ascension test plans.

The staff reviewed the licensee's justification for not performing certain large load transient tests that were originally performed as part of the startup test program. These large load transient tests are listed and discussed in Table 2.12-2 of Attachment 5 to the LAR. The tests, originally performed at various OLTP levels, include an Automatic Control System Checkout and Load Swing Test (originally performed from 50 to 100-percent OLTP); Generator Trip Test (originally performed at 100-percent OLTP); and Natural Circulation Test (originally performed at hot standby conditions). The justification for not performing these tests was presented in Section 2.12.1.2.7, "Justification for Exception to Transient Testing," of Attachment 5 to the LAR, which provides a discussion of the PATP covering power ascension up to the full EPU power level of 3020 MWt to verify acceptable performance.

The licensee's basis for not performing certain original startup tests, including large transient tests, as part of the proposed EPU PATP primarily relies on an analytical justification using the NRC-approved computer code CENTS to evaluate plant responses to Condition I and II initiating events at EPU conditions. As stated in the LAR, the CENTS code is acceptable for analyzing operational transients for CE designed PWRs and has been used on other CE designs including Waterford 3; ANO-2; SONGS, Units 2 and 3; and the PVNGS, Units 1, 2, and 3. The licensee also stated in the LAR that additional justification for not performing certain original startup tests included performance of post-modification testing of EPU-related plant modifications to ensure proper installation; performance of system surveillance tests as required to verify that the planned modifications meet applicable performance criteria; performance of integrated plant analyses to define the performance criteria of the various plant modifications necessary to accommodate the uprated power; review of the original startup test program; St. Lucie 2 plant-specific operating experience at greater than OLTP power levels; and industry experience at other previously uprated PWRs. The licensee stated that the analysis results and the evaluation of plant data acquired during power ascension are used, in part, in lieu of performing large transient testing to verify that the plant systems are capable of performing safely in the uprated condition.

The licensee presented a comparison of the proposed EPU tests to those performed during original plant startup in Table 2.12-2 of Attachment 5 to the LAR to address the staff's review criteria in Section III.C.2 of SRP 14.2.1. The licensee concluded that no large load transient tests are required to be performed as part of the St. Luice 2 EPU PATP since such tests would not confirm any new or significant aspect of performance not already demonstrated through analysis, by previous operating experience, or routinely through plant operations.

Industry PWR Transient Operating Experience at Uprated Power Levels

With respect to the review criteria established in SRP Section III.C.2, the licensee stated in the LAR that satisfactory post-EPU industry operating experience has been demonstrated at greater than original power levels at two other PWRs of similar design to St. Lucie 2. Section 2.12.1.2.2 of Attachment 5 to the LAR states, in part, that applicable industry operating experience comes from Waterford 3 and ANO-2 plants which are similar in design to that of St. Lucie 2. In April 2005, the staff approved an 8-percent EPU for Waterford to 3716 MWt; and in April 2002, approved a 7.5-percent uprate for ANO-2 to 3026 MWt. Both are CE designs and nearly identical to that of St. Lucie 2. In November 2005, Waterford 3 experienced a manual reactor trip from 100-percent power (approximately 109.5-percent of OLTP) due to a total loss of circulating water. According to the LAR and further supported by Licensee Event Report (LER) 2005-005, the integrated plant control systems operated satisfactorily in automatic to stabilize the plant posttrip and safety systems responded as designed. In December 2002, ANO-2 experienced an unplanned post-EPU reactor trip. The LAR stated that a review of the data from the trip indicated that plant performance had been adequately predicted by the calculation method used for control systems and integrated plant transient response evaluation for EPU. In accordance with RS-001, industry operating experience may be used by the licensee to support the basis for not performing certain original startup tests, including large transient tests, as part of the proposed EPU PATP.

St. Lucie 2 Plant-Specific Transient Experience at Uprated Power Level

Another factor used by the staff in its review of the licensee's justification for not performing large transient testing as part of the proposed EPU PATP were actual plant transient events experienced at St. Lucie. The licensee provided information in the LAR regarding one trip from full power in the past decade. The licensee stated that during the trip, safety equipment operated per design, and the unit was safely brought to Mode 3. The trip occurred at 100-percent CLTP (2700 MWt), which translates to approximately 105.5-percent OLTP, since the NRC approved a 5.5-percent stretch power uprate for both Units 1 and 2 on November 23, 1981. FPL stated in the LAR that CENTS analyses showed similar results for trips from 2700 MWt and EPU requested power level of 3020 MWt.

The staff reviewed the licensee's justification for not performing certain original startup tests against the review criteria established in SRP 14.2.1. In justifying test eliminations or deviations, St. Lucie 2 addressed several factors discussed in SRP Section III.C.2. These factors included industry operating experience at previously uprated PWRs, plant response to actual reactor trips for other similar PWRs, and experience gained from actual plant-specific events. Additionally, the FPL referenced the use of the NRC-approved WCAP-15996-P-A, Revision 1, which describes use of the CENTS computer code to analyze operational transients for CE designed PWRs. Based on the review, the staff concludes that the St. Lucie 2 EPU PATP provides reasonable assurance that plant SSCs that are affected by the proposed EPU will perform satisfactorily in service at the proposed power uprate level, and that the program complies with the QA requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," including specific review criteria contained in Section III.C.2 of SRP 14.2.1 and other staff guidance provided in RS-001. Therefore, the proposed power ascension and test plan is acceptable.

2.12.1.4 SRP 14.2.1, Section III.D, Evaluate the Adequacy of Proposed Transient Testing Plans

This Section specifies the guidance and acceptance criteria the licensee should use to include plans for the initial approach to the increased EPU power level and testing that should be used to verify that the reactor plant operates within the values of EPU design parameters. The test plan should assure that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the design basis for the facility. During testing, safety-related SSCs relied upon during operation shall be verified to be operable in accordance with existing TS and QA program requirements. The following should be identified in the EPU test program:

- The method in which initial approach to the uprated EPU power level is performed in an incremental manner including steady-state power hold points to evaluate plant performance above the original full-power level,

- Appropriate testing and acceptance criteria to ensure that the plant responds within design predictions including development of predicted responses using real or expected values of items such as beginning-of-life core reactivity coefficients, flows, pressures, temperatures, response times of equipment, and the actual status of the plant, not the values or plant conditions used for conservative evaluations of postulated accidents,
- Contingency plans if the predicted plant response is not obtained, and
- A test schedule and sequence to minimize the time untested SSCs important to safety are relied upon during operation above the original licensed full-power level.

The licensee stated in the LAR that during the EPU startup, power will be increased in a slow and deliberate manner, stopping at pre-determined power levels (test plateaus) for steady-state data gathering and formal parameter evaluation, consistent with the PATP. A summary of the St. Luce 2 PATP is provided in Table 2.12-1, "EPU Power Ascension Test Plan," of the LAR. The typical post-refueling power plateaus will be used until the current full power condition (2700 MWt) is attained at approximately 89 percent of the EPU full power level (3020 MWt), with additional equipment and post-modification testing performed to verify satisfactory performance of the modification in accordance with the design. Prior to exceeding the current licensed core thermal power of 2700 MWt, the data gathered at the pre-determined power plateaus will allow verification of the performance of the EPU modifications. By comparison of the plant data with pre-determined acceptance criteria, the test plan will verify that expected interactions between the various modifications have occurred such that integrated plant performance is demonstrated to be within design predictions.

Once at approximately 89 percent (2700 MWt) of EPU power, power will be slowly and deliberately increased through four additional test plateaus, each differing by approximately 3 percent of the EPU RTP. Both dynamic performance during the ascension and steady-state performance for each test plateau will be monitored, documented and evaluated against pre-determined acceptance criteria and expected values. In addition to the steady-state parameter data gathered and evaluated at each test condition. The PATP consists of a combination of normal startup and surveillance testing, post-modification testing, and power ascension testing deemed necessary to support the proposed EPU.

The staff concluded that the proposed test plan will adequately assure that the test objectives, test methods, and test acceptance criteria are consistent with the design basis for the facility; and that the test schedule would be performed in an incremental manner with appropriate hold points for evaluation.

<u>Conclusion</u>

The staff has reviewed the licensee's EPU power ascension and testing program, including plans for the initial approach to the proposed maximum licensed thermal power level, transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and the test program's conformance with applicable regulations. The licensee's test program includes primarily power ascension monitoring, post-modification testing and analytical evaluation, using the NRC-approved transient analysis code CENTS, with no large transient testing proposed. The staff reviewed the licensee's justification for not performing large transient testing as discussed in Attachment 5 to the LAR. Such justification included industry operating experience from previously uprated PWRs, St. Lucie 2 plant-specific operating experience at power level greater than OLTP, and analytical evaluations and analysis of transient events.

Based on the review, the staff concludes that the licensee's proposed EPU test program provides adequate assurance that the plant will perform as expected and that SSCs affected by the proposed EPU, or modified to support the proposed power increase, will perform satisfactorily in service; and satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," including the staff guidance and review criteria in SRP 14.2.1 and other guidance provided in RS-001. Therefore, the staff finds the proposed EPU acceptable with respect to the power ascension and test program.

2.12.2 Power Ascension and Testing Plan (BOP systems consideration)

The NRC staff's review of EPU test plans for BOP considerations focuses on modifications to BOP systems and the integrated response of the modified BOP systems to transients initiated from the full EPU power level. The staff evaluates the licensee's proposed EPU testing program to assure that, in conjunction with plant operating experience, computer modeling, and analyses, SSCs important to safety will perform satisfactorily in service at the requested increased plant power level. For most DBAs, the BOP systems are not essential to mitigate the event. However, the reliability of BOP systems affects the frequency of certain design basis events and the frequency of challenges to certain safety-related components. Therefore, consistent with the guidelines of Section 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," of the NRC SRP, the staff verifies that the proposed EPU test program adequately demonstrates the performance of SSCs important to safety that meet any of the following criteria: (1) the performance of the SSC is impacted by EPU-related modifications, (2) the SSC is used to mitigate an AOO described in the plant-specific design basis, and (3) performance of the SSC can be affected by integrated plant operation or transient conditions.

The staff reviewed the information provided in Section 2.12 of the St. Lucie 2 EPU licensing report against the considerations discussed in SRP Section 14.2.1 with respect to the BOP area of review. In addition to setpoint, pressure, and flow changes associated with the EPU, significant EPU modifications to BOP systems include replacement of the heater drain pumps, replacement of the high-pressure FW heaters and moisture-separator/reheaters, modifications to other FW heaters and controls, replacement of the main FW pumps, modification of the FW control valves, modification of the steam bypass control system, and replacement of the main high-pressure and low-pressure turbines.

The staff reviewed the scope of integrated plant testing proposed for evaluation of physical modifications associated with the power uprate. In many instances, the staff considers system and component level testing adequate to assure that the modified systems and components would perform acceptably in service, but integrated testing may be necessary where new or complicated system interactions exist. The licensee proposed to modify the steam bypass control system such that it would retain the capacity to pass the same fraction of rated steam flow at EPU conditions as the current system passes at current licensed thermal power. The licensee listed proposed post-modification testing of the steam bypass control system in Table 2.12-3, "Post-Modification testing," of the EPU licensing report and specified performance of dynamic system testing to verify adequate performance of the modified system, in addition to channel calibrations and functional stroke testing. The staff reviewed this test plan and concluded testing of the steam bypass control system would provide reasonable assurance of the important to safety function of relieving steam to the main condenser to control SG pressure and remove residual heat. Because the licensee is proposing neither to modify nor to credit additional capacity for the atmospheric steam dump valves, the staff concluded that integrated plant transient testing for the purpose of demonstrating the capacities of the atmospheric steam dump valves is not necessary. Adequate operation of the replacement main high pressure and low-pressure turbine would not require integrated testing because testing of the overspeed protection system provides reasonable assurance that the important to safety function of preventing turbine missile generation would be satisfied. Therefore, the staff concluded that integrated plant testing of these modifications would not be necessary. However, integrated testing and evaluation of the FW system modifications would provide the greatest assurance the system will perform its important to safety function of heat removal from the RCS during normal operation, including moderate transient conditions.

The licensee provided a comparison of the original plant start-up testing to the EPU power ascension test plan in Table 2.12-2, "Comparison of EPU Tests to Original Startup Tests," of the EPU licensing report. This table addressed testing involving integrated plant control system response, and indicated that large transient testing was not necessary to demonstrate acceptable performance of equipment important to safety at EPU operating conditions. The licensee specified performance of minor transient testing associated with routine power ascension and provided justification for exceptions to larger transient testing in Section 2.12.1.2.7 of the EPU licensing report. In this section, the licensee described that the limited testing and measurements included in the power ascension test plan would provide an indication that no unanticipated interactions had been introduced and the FW control system would operate properly at EPU conditions. The licensee presented details of the power ascension test plan in Table 2.12-1, "EPU Power Ascension Test Plan." In addition, the licensee described operating experience applicable to St. Lucie 2 and system-level modeling of plant response to larger transients using the CENTS code.

Section 2.12.1.2.6.1, "Transient Analytical Methodology," of the EPU licensing report described how the licensee used the CENTS computer code to evaluate the plant transient response. With respect to BOP system performance, the transients evaluated for normal operation, including AOOs, are most relevant because the BOP systems would be expected to operate throughout many these transients. The licensee listed the specific transient events evaluated using the CENTS code in Table 2.12-3, "NSSS Transients Evaluated for EPU with the CENTS Code." These transients included a turbine trip, a reactor trip, and a variety of step load changes of various magnitudes from varying initial power levels. The licensee benchmarked the CENTS code to the following St. Lucie 2 transients to refine the EPU model:

- Unit 2 manual reactor trip from 100 percent power on June 4, 2008, following a loss of a main FW pump
- Unit 2 manual reactor trip from 100 percent power on June 7, 2008, following a condensate pump trip

The staff provided RAI SBPB-5, by email dated August 17, 2011, requesting the licensee to discuss how the FW system will be assessed with actual transient testing prior to EPU implementation and also to confirm if the replacement FW pumps and FW control system will respond in a manner similar as the CENTS-modeled transient. The staff also requested for the licensee to justify its position in the case of actual transient testing being excluded prior to EPU operation. In the response to RAI SBPB-5, provided by letter dated October 12, 2011, the licensee stated that agreement between the CENTS model results and the actual plant response during the benchmarking process and the incorporation of FW system equipment in the CENTS model provided confidence that CENTS cases adequately model plant response at EPU conditions.

The licensee described that the FW control system would be monitored during the EPU power ascension to ensure the FW controls are operating correctly and that SG level is automatically controlled within operating limits. This monitoring in combination with completed analyses and operating experience would provide reasonable assurance that the FW system and associated control systems would operate properly at the proposed uprated power level.

The NRC staff assessed the licensee's power ascension test plan against the guidance of SRP Section 14.2.1. The staff considered the proposed modifications to the steam bypass control system, main turbine, and FW systems to be of limited scope. Operating experience indicated that similar limited scope modifications have been successfully implemented at other units, including Combustion Engineering reactors comparable to St. Lucie 2. The licensee modeled the transient response of plant systems to provide reasonable assurance that the plant would continue to respond to transients at the EPU power level consistent with its design basis. Detailed plant modeling demonstrated that the condensate and FW systems, with EPU modifications in place, would have ample margin to respond as assumed in the transient analysis. Therefore, the NRC staff determined that, for the limited scope of BOP modifications, demonstration of acceptable BOP performance during the planned power ascension test program combined with the described computer modeling of postulated transients would provide reasonable assurance that BOP systems will function as designed for EPU operation.

2.13 Risk Evaluation

Regulatory Evaluation

The licensee did not request the relaxation of any deterministic requirements for their proposed power uprate, and the staff's approval is primarily based on the licensee meeting the current deterministic engineering requirements. As discussed in RS-001, Section 13, a risk evaluation is conducted to determine if "special circumstances" are created by the proposed EPU. As described in Appendix D of SRP Chapter 19.2, special circumstances are any issues that would potentially rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements. Specific review guidance is contained in Matrix 13 of RS-001 and its attachments. Further guidance on how to make a determination of special circumstances is provided in Appendix D to SRP Chapter 19.2.

The staff's review addresses the risk associated with operating at EPU conditions (10 percent greater than the currently licensed power level) in terms of changes in CDF and LERF from internal events, external events, and shutdown operations. In addition, the NRC staff's review addresses the quality of the risk analyses used by the licensee to support the application for the proposed EPU. This includes a review of licensee actions to address issues or weaknesses that may have been raised in previous staff reviews of the licensee's IPE, IPEEE, or by industry peer reviews. The staff used the guidance provided in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," to focus the review of this nonrisk-informed submittal.

Technical Evaluation

The staff reviewed the risk evaluation submitted for St. Lucie Plant 2 by FPL, as supplemented by responses to the staff's RAI. The licensee has provided an estimate of the increase in risk (CDF and LERF) assuming EPU conditions. A combination of quantitative and qualitative methods was used to assess the risk impact of the proposed EPU. The following sections provide the staff's technical evaluation of the risk information provided by the licensee. The staff's evaluation did not involve an in-depth review of the licensee's risk evaluation.

Probabilistic Risk Assessment (PRA) Model Quality

The quality of the licensee's PRA used to support a license application needs to be commensurate with the role the PRA results play in the decision-making process. The staff's approval is based on the licensee meeting the current deterministic requirements, with the risk assessment providing confirmatory insights and ensuring that the EPU creates no new vulnerabilities.

IPE/IPEEE

The licensee submitted the St. Lucie 2 IPE, which is based on a full scope level 2 PRA performed in fulfillment of GL 88-20. The NRC issued an SER stating that the licensee did not identify any severe accident vulnerabilities associated with either core damage or containment failure. The IPE submittal identified changes to the plant, procedures, and training as part of the IPE process.

The licensee submitted the St. Lucie 2 IPEEE to the NRC in response to Supplement 4 of GL 88-20. The NRC issued an SER that concluded that the licensee's IPEEE identifies most likely severe accidents and severe accident vulnerabilities from external events.

In its submittal, the licensee states that all vulnerabilities identified in the IPE and IPEEE have been resolved and no new vulnerabilities are introduced as a result of the EPU.

PRA Peer Review

In July 2002, CEOG performed a peer review of the St. Lucie 2 PRA. The review followed a process that was adopted from industry reference NEI-00-02, Rev A3. The review identified nine A level Facts and Observations (F&Os) and 30 B level F&Os. A-Level F&Os are defined as being extremely important and necessary to address in order to assure the technical adequacy of the PRA, while B-level F&Os are defined as being important and necessary to address, but may be deferred until the next PRA update. The licensee provided a summary of the A-Level and B-Level F&Os and their resolutions.

Additionally, in July 2009, a focused peer review was conducted for LERF and common cause failures (CCFs). The LERF review resulted in closure of all LERF related F&Os. No open items and no EPU impacts were identified. The CCF review closed all risk-significant open items. New F&Os generated during that review were determined to not impact the EPU PRA risk assessment.

The staff finds that all F&O findings were properly assessed and dispositioned in regard to this application.

Conclusions Regarding the Quality of the St. Lucie PRA

The NRC staff's evaluation of the licensee's submittal focused on the capability of the licensee's PRA and other risk evaluations (e.g., for external events) to analyze the risks stemming from pre- and post-EPU plant operations and conditions. The NRC staff's evaluation did not involve an in-depth review of the licensee's PRA; instead, it involved an evaluation of the information provided by the licensee in its submittal; considered the review findings for the St. Lucie IPE and IPEEE; and reviewed the CEOG peer review open F&Os and their dispositions for this application.

Based on its evaluation, the NRC staff finds that the St. Lucie 2 PRA models used to support the risk evaluation for this application have sufficient scope, level of detail, and technical adequacy to support the evaluation of the EPU.

Internal Events Risk Evaluation

The licensee assessed the risk impacts from internal events resulting from the proposed EPU by reviewing the changes in plant design and operations resulting from the proposed EPU, mapping these changes onto appropriate PRA elements, modifying affected PRA elements as needed to capture the risk impacts of the proposed EPU, and requantifying the St. Lucie 2 PRA to determine the CDF and LERF of the post-EPU plant.

Initiating Event Frequencies

The St. Lucie 2 PRA model includes initiating event categories which includes transient initiating events, LOOP, LOCA initiators, SGTR initiators, ATWS initiators, and internal flooding initiators.

Transients – The licensee stated that the evaluation of the plant conditions and procedural changes for EPU conditions do not result in any new transient initiators, nor directly impact transient initiator frequencies significantly. Sensitivity calculations were performed that increased the transient initiator frequency to bound the various challenges to the plant from transients resulting from loss of electrical buses, reactor trip, PORV challenges, and increased flow accelerated corrosion.

LOOP – The licensee states in its submittal that several plant modifications will be undertaken to ensure the plant, at EPU conditions, is more robust to external LOOP. Conditional LOOP likelihood is also expected to decrease as a result of a modification to rearrange post-trip SIAS non-safety loads. As a consequence, increases in switchyard, plant centered or grid LOOP frequency are not expected. Sensitivity calculations were performed to show negligible risk increase due to increase in LOOP frequency.

Support System – The licensee states that no significant changes to support systems are planned in support of the EPU and no significant impact on support system initiating event frequencies due to the EPU are postulated.

LOCA – The licensee did not identify any impact on LOCA or interfacing system LOCA frequencies resulting from the EPU. A sensitivity study concluded that increasing the transient induced PORV challenge frequency by fifty percent resulted in a CDF increase of 1E-9 per year.

SGTR – The licensee states that as changes to the SG operating conditions are minimal, the existing PRA modeling for SGTR events is considered applicable to EPU conditions.

ATWS – The significance of the ATWS event is evaluated in terms of unfavorable exposure times, which reflect the fraction of cycle the plant would have to wait before the MTC is sufficiently negative such that ATWS events could be mitigated with charging pumps and other resources. The current unfavorable exposure times identified in the plant PRA is 0.22, the EPU ATWS unfavorable exposure times was increased to 0.255. To evaluate the risk impact of the using the unfavorable MTC probability of 0.255, the basic event probability was changed from 0.22 to 0.255. St. Lucie 2 analyses indicate that the EPU ATWS CDF increased by approximately 4.6E-8 per year and LERF increased by 1.11E-09 per year. This analysis conservatively assumes that core damage results when the RCS pressurizes to above 3700 psia. While EPU ATWS events do increase slightly, their significance is low due to the low frequency of failure of rods to insert.

Internal Flooding – The licensee states that other than the pipe break initiators discussed, there are no substantive changes to other systems that might induce internal flooding; therefore, the flooding impacts and initiator frequencies remain unchanged.

Overall EPU Impact on Initiating Events

The staff finds the licensee adequately addressed internal initiating event frequencies based on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Furthermore, based on the licensee's sensitivity calculation, any short-term risk impact from break-in failures caused by the numerous BOP equipment changes is expected to be very small. Finally, the staff notes that any changes observed in the future in initiating event frequencies will be identified and tracked under the plant's existing performance monitoring programs and processes and will be reflected in future updates of the PRA, based on actual plant operating experience.

The NRC staff has not identified any issues associated with the licensee's evaluation of internal initiating event frequencies that would significantly alter the overall risk results or conclusions for this license amendment. Therefore, the staff concludes that there are no issues with the evaluation of internal initiating event frequencies associated with the St. Lucie 2 internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment.

Component Failure Rates

The licensee concluded in its submittal that the EPU would not significantly impact long-term equipment reliability due to the replacement/modification of plant components. The majority of hardware changes in support of the EPU may be characterized as either replacement of components or upgrade of existing components. The licensee described no planned operational modifications as part of the EPU that involve operating equipment beyond design ratings. Sensitivity studies were performed on selected components or systems where changes due to EPU had the potential to impact plant performance.

The staff finds that the licensee adequately addressed equipment reliability based on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Further, any short-term risk impact of the numerous BOP equipment changes, due to break-in failures, is expected to be very small. Finally, the staff notes that the licensee's component monitoring programs, including equipment modifications and/or replacement are being relied upon to maintain the current reliability of the equipment.

The staff has not identified any issues associated with licensee's evaluation of component reliability that would significantly alter the overall results or conclusions for this license amendment. Therefore, the staff concludes that there are no issues with component reliabilities/failure rates modeled in the St. Lucie 2 internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment and that the expectation is that there will be no change in component reliability as a result of the EPU.

Accident Sequence Delineation and Success Criteria

Success criteria specify the performance requirements on plant systems performing critical safety functions. The licensee performed a review to assess the effect of the increase in thermal power level on success criteria. Safety functions, and related EPU impacts on success criteria considered by the licensee, are discussed in this section.

Increased decay heat due to EPU results in a more rapid depletion of inventory in the SG and degrades the once through cooling (OTC) heat removal capability. Should FW not be recoverable, the increased core decay power and the associated decreased boil-off time impacts operator timing and equipment required for successful implementation of OTC. To address this potential loss of capability, the licensee increased the SG low level reactor trip setpoint and made changes to the plant emergency operating procedures. These changes are

1. Increase the narrow range SG low level reactor trip setpoint from 20.5 percent to 35 percent

2. Modify Emergency Operating Procedure 1-EOP-01, Standard Post Trip Actions procedures to trip all RCPs upon indication of a TLOFW

The intent of these actions is to increase the inventory in the SG following TLOFW events to increase the time available for operator to implement OTC. MAAP analyses show that implementation of these actions following a TLOFW with a reactor trip on SG low level will increase the time to successfully implement OTC from 30 minutes under current conditions to 37 minutes at EPU conditions. These changes also provide an additional 15 minutes to restore FW. In addition, to reduce the potential for AFW unavailability during an event, St. Lucie 2 is modifying surveillance procedures to reduce potential pre-initiator human failure events associated with mispositioning of the AFWS discharge valves. Combined, these EPU plant improvements will provide a safety benefit.

There are no changes in reactivity control methods or effectiveness due to EPU. However, the increased power level results in a longer period of unfavorable MTC during ATWS events. As the frequency of ATWS is low, the impact on risk is small.

As a result of changes in boric acid concentrations and higher decay heat following LOCAs, the EPU also impacts RCS core heat removal. RCS and core heat removal can be lost due to boron precipitation following a medium or LBLOCA. Anticipated changes in boron concentration have been considered in establishing time for operator to initiate hot leg injection. The licensee states that changes in boron concentration have not resulted in changes to the long-term cooling timing implementation requirements. Consequently, the risk impact of this change is negligible.

As a result of the EPU, St Lucie 2 is also planning to modify the pressurizer level control program since the level is estimated to have larger variation for EPU. The pressurizer level control system maintains the pressurizer level within a programmed band consistent with measured T_{avg}. The programmed level is designed to maintain a sufficient margin above the low-level alarm where the heaters turn off while maintaining the level low enough that a sufficient steam volume is maintained to ensure the pressurizer does not go solid during accidents and transient conditions. The staff expects that any increase in PORV challenges following implementation of the proposed EPU would be identified under the licensee's performance monitoring programs and processes and incorporated into future model updates.

The staff finds that the licensee's assessment of the impact of the proposed EPU on success criteria appears to be reasonable and that there are no issues related to the St. Lucie 2 success criteria that would rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

Operator Actions

Human Reliability Analysis (HRA) – EPU has the general effect of reducing the time available for the operators to complete recovery actions, because of the higher decay heat level after EPU implementation. The plant is dependent on operating crew actions for successful accident mitigation. The success of these actions is, in turn, dependent on a number of performance shaping factors and that the performance shaping factor that is principally influenced by the EPU is the time available within which to detect, diagnose, and perform required actions. The higher power levels normally result in reduced time available for some operator actions.

The licensee states that the St. Lucie HRA was developed in a manner to conform to RG 1.200. Each operator action was evaluated using the EPRI HRA Calculator, and where appropriate, response time windows were evaluated using plant specific MAAP 4.0.7 accident analysis simulations. The Human Cognitive Correlation/Operator Reliability (HCR/ORE) and Cause Based Decision Tree Methodology (CBDTM) methodologies were applied to all of the human error events, and for each event, the greater of the calculated HEPs from the two methodologies was used in the PRA model. In addition, the licensee utilized the accident sequence evaluation program for pre-initiator human failure events to identify and increase surveillance frequencies for EPU risk significant valves, thereby decreasing CDF and LERF.

EPU has no impact on estimated operator recovery actions for approximately one half of the operator actions included in the PRA. For several HEPs, the SG low-level setpoint change resulted in a significant benefit. The increased time window improves the reliability of three basic operator actions following an instantaneous TLOFW: (1) restoration of MFW, (2) restoration of AFW and (3) implementation of OTC.

A licensee review of the top one hundred EPU cutsets included many pre-initiator human failures. As a result, the surveillance frequency was increased on selected valves in the AFW system resulting in a risk-significant decrease in EPU CDF and LERF. Changes to plant EOPs and surveillance procedures will require weekly surveillance on selected risk-significant valves to ensure proper alignment. This action reduced the failure probability for these valves an order of magnitude from 1.3E-04 to 1.33E-05.

In response to an RAI, the licensee clarified that St. Lucie Unit 1 has more operator actions modeled than St. Lucie 2 primarily because of design differences between the units. These differences include: (1) larger PORVs and CST for Unit 2 (2) AOV control valves to the SDC HXs for Unit 1 while MOVs are employed for Unit 2 (3) differences in MFW isolation logic and (4) Unit 2 includes a dedicated hot leg recirculation system using the HPSI pump whereas Unit 1 has hot leg recirculation integrated into the plant procedures using flow paths created via re-alignments of either the LPSI or other alternate backup flowpaths.

Overall EPU Impact on Operator Actions

Based on the licensee's submitted information, the NRC staff finds that it is reasonable to expect that the main impact of the EPU is to reduce the time available for some operator actions, which will increase the associated HEPs. However, these increased HEPs are not expected to create significant impacts, unless a number of critical operator actions cannot be performed at the increased power levels. The NRC staff has not identified any issues associated with the licensee's evaluation of operator actions that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the operator actions evaluation associated with the St. Lucie internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment.

Internal Events Risk Results

Level 1 PRA estimates the frequency of core damage for different initiating events that have the potential to occur at the plant. The impact of increases in initiating event frequencies was presented as sensitivity studies in the application and the outcome of these studies show negligible increases in core damage frequency.

Level 2 PRA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. The simplified Level 2 evaluation calculates the LERF using CDF accident sequences and bins that result in LERF, intact containment, late containment failure and small early release end states. The licensee states that the calculations considered all relevant severe accident phenomenology.

Table 1: Internal Events CDF and LERF Risk Metrics

	Pre-EPU	Post-EPU	Delta Change	Percent decrease
CDF	5.04×10^{-6}/year	5.03×10^{-6}/year	-9.9×10^{-9}/year	0.1
LERF	2.77×10^{-7}/year	2.60×10^{-7}/year	-1.7×10^{-8}/year	6.1

The above results are consistent with RG 1.174, since this application represents decreases in internal events CDF and LERF. The application does not raise concerns of adequate protection.

The staff finds the licensee's evaluation of the impact of the proposed EPU on at-power risk from internal events is reasonable and concludes that the base risk due to the proposed EPU is acceptable and that there are no issues that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

External Events Risk Evaluation

The licensee does not have fire or seismic PRA models. The IPEEE studies used the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology to address external risk from fire sources. For the Seismic IPEEE process, the licensee used a site-specific seismic program associated with USI A-46, “Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors,” to address the seismic aspects of the IPEEE. High winds, external flooding, and other external events (e.g., transportation and nearby facility accidents) were addressed by reviewing the plant environs against regulatory requirements. The licensee provided a qualitative assessment of the impact of EPU implementation on external event risk, which is discussed below.

Internal Fire Risk

For the IPEEE fire analysis, St. Lucie implemented the EPRI FIVE methodology. The IPEEE staff evaluation notes the licensee analyzed all fire areas and compartments using a reasonable screening methodology. A qualitative evaluation of EPU modifications was performed with respect to fire risk. The evaluation included an assessment of the impact of EPU on the initial IPEEE fire screening, and a reassessment of the three non-screened fire areas: main control room, cable spreading room and switchgear room. The evaluation concluded that EPU changes would not impact the initial plant fire screening.

The combined fire risk estimates for the main control room, cable spreading room, and switchgear room are on the order of 7.8E-06 per year for each room. An assessment of the impact of planned EPU changes on the fire risk for these compartments indicates the impact to be negligible as fire risk for these rooms did not credit operator actions. The licensee concluded that the combined CDF of the screened compartments was approximately 1.4E-06 per year.

Fire frequencies and fire mitigation (e.g., fire suppression, fire brigade response) are not related to reactor power level, therefore the staff does not expect the post-EPU risk to significantly increase due to fire and create the “special circumstances” described in Appendix D of SRP Chapter 19.2 for a non risk-informed application.

Seismic Risk

In the seismic IPEEE, the site-specific program for seismic adequacy evaluations for St. Lucie 2 addresses only a subset of the elements specified in NUREG-1407 as recommended items that should be considered in the seismic IPEEE of a reduced-scope plant. St. Lucie’s scaled-back site-specific seismic adequacy program was approved, in concept, by the NRC for the purpose of addressing USI A-46. The justifications sited by St. Lucie for performing a scaled-back analysis include: (a) very low probability of having an earthquake at the SSE level; and (b) very low values of potential offsite releases and potential risk reductions given the postulated accident scenarios and seismic hazards. St. Lucie’s approach to seismic evaluation relied primarily on plant walkdowns and on the use of seismic review team judgment, supplemented with calculations, as needed, for resolving outliers.

EPU systems modifications were reviewed for their impact on safe shutdown. Through the review, it was concluded that none of the planned EPU plant modifications have any significant potential impact on seismic vulnerability. Therefore, the licensee judged the impact of EPU plant modifications on safe shutdown and associated plant risk due to seismic events to be negligible. Furthermore, the licensee states that all structural plant modifications and anchoring of all replacement components (safety and non-safety) for EPU will have the same or greater seismic capability than the current design basis.

Seismic risk was not quantified either for the current plant or for EPU implementation. However, in order to provide additional insight with respect to the effect of EPU on seismic risk, a focused seismic estimate was established. The primary purpose of the evaluation was to provide a risk estimate of the impact of operator actions following a seismic event. The analyzed event was a seismic initiated LOOP that occurs during ground accelerations with a magnitude between the operating basis earthquake (0.05g) and the beyond design basis earthquake (0.1g). This evaluation indicated that both current and EPU CDF estimates were very close to 4E-09 per year. Similarly, LERF estimates were on the order of 6E-10 per year.

The staff finds that the licensee's characterization of the seismic risk at St. Lucie 2 is not complete and that the steps undertaken during the seismic IPEEE process leads to an inconclusive risk estimate. In the IPEEE seismic evaluation, the NRC staff notes that there are several weaknesses in the licensee's seismic submittal; however, the staff indicates that the process used to address seismic risk was capable of identifying the most likely severe accidents and severe accident vulnerabilities. Based on a simplified approach to estimate the core damage frequency from a seismic margins approach and using the latest published USGS seismic hazards information, the staff estimates the St. Lucie seismic CDF is about or below 5E-5 per year. Since all structural plant modifications and anchoring of all replacement components (safety and non-safety) for EPU will have the same or greater seismic capability than the current design basis, and new vulnerabilities to a seismic event due to implementation of the EPU are negligible, the staff finds the delta seismic risk associated with the EPU to be insignificant. As such, the staff does not expect the seismic risk associated with the plant to rebut the presumption of adequate protection. For a risk-informed submittal, the staff would have investigated further the impact of seismic risk; however, for a nonrisk-informed submittal, the staff does not does not expect the post-EPU risk to significantly increase due to seismicity and create the "special circumstances" described in Appendix D of SRP Chapter 19.2.

Other External Events Risk

The St. Lucie IPEEE addresses events other than seismic and fires, including high winds, external floods, and transportation and nearby facility accidents. Consistent with the IPEEE guidance, the licensee reviewed the plant environs against regulatory requirements regarding these hazards and concluded that St. Lucie meets the applicable NRC SRP requirements and, therefore, has an acceptably low risk with respect to these hazards.

External Events Risk Conclusion

The staff has not identified any issues associated with the licensee's evaluation of the risks related to external events that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the external events risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the risk impact from external events resulting from the proposed EPU will be very small, based on the licensee's current risk evaluations.

Shutdown Risk Evaluation

The primary impact of the EPU on risk during shutdown operations is associated with the decrease in allowable operator action times in response to events. Reductions in available time for operators to take compensatory or mitigating actions could vary from several to ten or more minutes, dependent on the shutdown condition. A licensee SE demonstrates that the shorter available time window under EPU would not adversely impact safety consequences.

The most significant impact identified in the post-EPU risk assessment is that during mid-loop operation actions in response to loss of SDC could be subject to a shorter available time window. In response to an RAI, the licensee stated that procedures and associated personnel training will be maintained to ensure that adequate time to closure will be available. As the shutdown operation related procedures are condition driven, no significant risk impacts to the shutdown operations procedures are anticipated for EPU.

The staff has not identified any issues associated with the licensee's evaluation of shutdown risks that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the shutdown operations risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the impact on shutdown risk resulting from the proposed EPU will be negligibly small, based on the licensee's current shutdown risk management process.

Conclusion

The NRC staff has reviewed the licensee's assessment of the risk implications associated with the implementation of the proposed EPU and concludes that there are no issues with the licensee's risk evaluation that would create the "special circumstances" described in Appendix D of SRP Chapter 19. Therefore, the staff finds the risk implications of the proposed EPU acceptable.

3.0 FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION CHANGES

To achieve the EPU, the licensee proposed the following changes to the Facility Operating License and TSs for St. Lucie 2.

The NRC staff has reviewed the proposed TS changes presented in Attachments 1 and 3 of the licensee's amendment request and additional information (References 51; 62; 53) and provides the following evaluation:

1. TS 1.16, Definitions – Low Temperature Overpressure Protection

The definition in TS 1.16 specifies that the low temperature overpressure protection (LTOP) range is that operating condition when (1) the RCS cold leg temperature is less than or equal to that specified in Table 3.4.3, and (2) the RCS is not vent to containment by an opening of at least 3.58 square inches.

The proposed TS would delete the TS 1.16. The NRC staff found that (1) the actual values for the LTOP settings were specified in LCO 3.4.9.3, "Reactor Coolant System - Overpressure Protection Systems," and (2) the change was consistent with NUREG-1432, "Standard

Technical Specifications Combustion Engineering Plants," which include St. Lucie 2. The Standard TSs do not contain a definition for the LTOP range. Therefore, the NRC staff determined that the proposed deletion did not change the TS requirements and was acceptable.

2. TS 1.25, Definitions – Rated Thermal Power

The definition of the rated thermal power was proposed to change from 2700 MWt to 3020 MWt.

The NRC staff found that the proposed rated thermal power of 3020 MWt correctly reflected the power level limit assumed in the acceptable EPU safety analyses discussed in Section 2.8.5 of this SE. Therefore, the NRC staff determined that the proposed TS change was acceptable.

3. TS 2.1, Safety Limits

The proposed TS revised Figure 2.1-1, "Reactor Core Thermal Margin Safety Limit Lines - Four Reactor Coolant Pumps Operating."

The proposed TS Figure 2.1-1 shows the operating limits of thermal power, RCS pressure, and vessel inlet temperature with four RCPs operating for which SAFDLs (i.e., centerline fuel melting temperature and the DNBR safety limits) are not exceeded. The NRC staff found that the revised TS Figure 2.1-1 was considered as operating limits in the acceptable EPU safety analyses discussed in Section 2.8.5 of this SER, and therefore, determined that the revised figure was acceptable.

4. TS Table 2.2-1- Reactor Protective Instrumentation Trip Setpoint Limits

The following items in TS Table 2.2-1 were proposed to change:

4.1 Functional Unit 6, Steam Generator Pressure – Low: Note (2) on the "Trip Setpoint" and "Allowable Value" would be changed to a superscript. The NRC staff found that the changes were editorial in nature and did not affect the TS requirements.

4.2 Functional Unit 8, Steam Generator Level – Low: the Trip Setpoint is changed from "20.5% (3)" to "35.0%$^{(3)}$," and the Allowable Value is changed from "19.5% (3)" to "35.0%$^{(3)}$." Based on the accident and transient analysis and the greater operator response time, the staff has determined that the rationale for changing this setpoint is acceptable.

4.3 Functional Unit 14, Reactor Coolant Flow – Low: The proposed TS would change "95.4% of design Reactor Coolant flow with four pumps operating*" in the "Trip Setpoint" and "Allowable Value" columns to "95.4% of minimum Reactor Coolant flow with four pumps operating*."

In the EPU safety analysis, the minimum reactor coolant flow for four reactor coolant pumps (RCPs) operating conditions was used to show that the reactor core thermal margin safety limits were met. The terminology for the trip setpoint and available value for reactor coolant flow - low with four RCPs operating conditions as well as Note (*) was revised from "design Reactor Coolant flow" to "minimum Reactor Coolant flow." The NRC staff agreed with the licensee that the changes provided a more accurate description of the actual plant parameters and ensured that reactor coolant flow requirement was consistent with the value assumed in the acceptable EPU safety analysis. Therefore, the NRC staff concluded that the changes were acceptable.

4.4 Footnote (*) in “Trip Setpoint” and “Allowable Value” columns of Functional Unit 14: The current footnote states that “*Design reactor coolant flow with four pumps operating is the minimum RCS flow specified in the COLR Table 3.2-2.”

As discussed in below item 10 of this section of the SER, the required minimum RCS flow was retained in the TS 3.2.5. This footnote would be changed (Reference 62) to “For minimum reactor coolant flow with four pumps operating, refer to Technical Specification LCO 3.2.5.” The change, referencing the TS and not COLR for the reactor coolant flow requirements, was consistent with the acceptable LCO 3.2.5, and therefore, was acceptable.

5. Boron Control

The following two TSs provide direction for emergency boration at a boration rate of greater or equal to 40 gpm in the event the shutdown margin is not maintained as specified in the Core Operating Limits report (COLR).

5.1 TS 3/4.1.1.1 (for Modes 1, 2*, 3 and 4) - Shudown Margin - T_{avg} Greater Than 200 °F
5.2 TS 3/4.1.1.2 (for Mode 5) - Shudown Margin - T_{avg} Less Than or Equal to 200 °F

In ACTION Section, the minimum boron concentration in the borated water sources was proposed to change from “greater than or equal to 1720 ppm boron or equivalent” to “greater than or equal to 1900 ppm boron or equivalent.” The NRC staff found that the proposed boron concentration was consistent with the minimum boron concentrations for the solution in the RWT specified in the proposed TS LCOs 3.1.2.7.b.2, 3.1.2.8.d.2 and 3.5.4.b, the safety injection tanks (SITs) specified in TS LCO 3.5.1.c and Note “*” to Mode 3 in TS 3.5.1 APPLICABILITY, and the boric acid makeup tank (BAMT) specified in TS LCO 3.1.2.7.a and TS Figure 3.1-1. Therefore, the NRC staff concluded that the boron concentration changes were acceptable.

6. TS 3/4.1.2.2 Reactivity Control System - Flow Path - Operating

The second set of LCO 3/4.1.2.2 requirements after “OR” currently numbered “a., b., and c.” would be renumbered to “d., e., and f.”.

The change removed duplicate numbering of LCO requirements. The NRC staff found that the proposed change provided clarification and supported the change to Note “*” of TS 3.5.2.d that referenced this specification. Therefore, the NRC staff concluded that the change was editorial in nature; it did not change the TS requirements; and therefore, was acceptable.

7. TS 3/4.1.2.7 - Borated Water Sources for Shutdown (Modes 5 and 6)

The following TS items would be changed:

7.1 LCO 3/4.1.2.7.a - The boric acid makeup tank (BAMT) parameters would be changed from “a minimum borated water volume of 3550 gallons of 2.5 to 3.5 weight percent boric acid (4371 to 6119 ppm boron).” to “a minimum borated water volume of 3550 gallons of 3.1 to 3.5 weight percent boric acid (5420 to 6119 ppm boron).”

7.2 LCO 3/4.1.2.7.b - The RWT minimum borated boron concentration is changed from "1720 ppm" to "1900 ppm."

The boric acid delivery analysis used to determine the requirements for the borated water sources was discussed in the response to RAI SRXB-33 and SRXB-34 (References 51; 53). Specifically, the analysis showed that for Modes 5 and 6, sufficient boric acid was available in the boric acid makeup tank (BAMT) and RWT in order to provide the required shutdown margin of TS LCO 3.1.1.2 following xenon decay and cooldown from the initial temperature of Mode 5 (200 °F) to the initial temperature of Mode 6 (140 °F).

In the response to RAI SRXB-33 and SRXB-34 follow-up (Reference 51), the licensee indicated that the methods used for the boric acid delivery analysis were based on the current analysis methods, previously approved by NRC for St. Lucie 2 (Reference 63).

For Modes 5 and 6, the boric acid delivery analysis at EPU conditions was performed for two cases: Case 1 used borated water only from the BAMT; and Case 2 relied on the water source from the RWT. The analysis assumed that the borated water added to the RCS was equal to the RCS volume shrinkage due to the cooldown while the pressurizer water level was maintained constant. The initial boron concentration was assumed to be at the most limiting concentration for Modes 5 and 6 based on the Mode 1 through 4 boric acid delivery analysis discussed in below item 8 of this SER section. The RWT and BAMT temperature was based on the maximum temperature, applicable to Modes 5 and 6, plus a temperature uncertainty of 4 °F. The use of the maximum temperature was conservative and acceptable, since the higher temperature would decrease the solution density, which resulted in a decrease in the mass of boron delivered to the RCS per unit volume.

The limiting results (Table SRXB-33-1 and Table SRXB-33-2 of Reference 53) from the analyzed configurations, with boron sources from either the RWT or BAMT, showed that the system delivery boron concentration exceeded the anticipated shutdown margin concentration requirements. This requirement would be verified for each core reload as part of the cycle specific reload analysis.

The BAMT volume in TS LCO 3.1.2.7.a and RWT volume in TS LCO 3.1.2.7.b reflected the analytical results with inclusion of the margin to account for unusable tank inventory, the inventory associated with the level measurement uncertainty, the inventory associated with auxiliary spray, and the minimum vortex prevention level. As for the TS required boron concentration, a 100 ppm boron concentration uncertainty was added to the nominal concentration of the both BAMT and RWT (SRXB-33, (Reference 53)).

Based on the above discussion, the NRC staff found that (1) the NRC-approved methods were used in determination of the required boron acid concentration and volume in the BAMT and RWT, (2) the results showed that the required shutdown margin in TS LCO 3.1.1.2 was maintained, and (3) the TS LCO 3.1.2.7.a and TS LCO 3.1.2.7.b adequately reflected the required boron concentration and volume including uncertainties. Therefore, the NRC staff determined that the proposed values of the boron concentration and volume in TS 3.1.2.7.a and TS 3.1.2.7.b were acceptable for the BAMT and RWT.

8. TS 3/4.1.2.8 - Borated Water Sources for Operating (Modes 1 through 4)

The following TSs would be changed:

8.1 LCO 3/4.1.2.8.d.2. The RWT minimum borated boron concentration would be changed from ”between 1720 and 2100 ppm” to “between 1900 To 2200 ppm”

8.2 TS FIGURE 3.1-1, “St Lucie 2 Min BAMT Volume vs. Stored BAMT Concentration” - This Figure would be replaced with new TS FIGURE 3.1-1, entitled “FIGURE 3/1 -1, Minimum BAMT Volume vs. Stored Boric Acid Concentration.”

The boric acid delivery analysis used to determine the requirements for the borated water sources was discussed in the response to RAI SRXB-33 and SRXB-34 (References 51; 53). Specifically, the analysis showed that for Modes 1 through 4, sufficient boric acid was available in the BAMT and RWT in order to provide the required shutdown margin of TS LCO 3.1.1.1 for a cooldown from hot standby to cold shutdown conditions.

In the response to RAI SRXB-33 and SRXB-34 follow-up (Reference 51), the licensee indicated that the methods used for the boric acid delivery analysis was based on the current analysis methods, previously approved by NRC for St. Lucie 2 (Reference 63).

For Modes 1 through 4, the analysis assumed that the plant was operating at 100 percent power with equilibrium xenon at the time of the reactor trip. Immediately following the reactor trip, the plant was shut down and held at zero power for a time period such that the xenon level returned to equilibrium 100 percent xenon power level. At this time, offsite power and letdown were assumed to be lost. No operator action was assumed for 30 minutes, during which time the RCS temperature rose. The thermal expansion due to a conservatively assumed temperature increase resulted in a rise in pressurizer level. Following the 30 minutes without operator action, plant operators initiated cooldown with makeup for liquid shrinkage sourced first from the BAMT and then the RWT when the BAMT was exhausted. This provided boration to the RCS. The cooldown rate used for Mode 1 through 4 conservatively included a holding period to prevent RV upper head voiding. Also the pressure reduction rate was limited such that sub-cooled conditions were maintained in the RCS.

The licensee identified following two conservative changes in the analysis for EPU conditions:

1. A cooldown rate of 11.0 °F/hour decreased from 12.5 °F/hour in the AOR was used. Using a slower cooldown rate was conservative, because a lower cooldown rate caused a longer duration to reach the cold shutdown temperature, which resulted in more positive reactivity addition due to the xenon decay effect, and

2. The initial RCS mass was determined at the RCS HZP temperature prior to the LOOP. The temperature was then assumed to rise by 25 °F during the 30 minutes prior to operator initiating a natural circulation cooldown. In the AOR, the initial RCS mass was based on the RCS HZP temperature plus 25 °F due to the RCS coolant heat-up following the LOOP. The cooldown initiation temperature was used to determine the fluid mass at the start of cooldown based on a fixed RCPB volume. An increase in temperature would result in a smaller calculated RCS fluid mass. Since additional mass would act as diluents in the boric acid delivery analysis, it was non-conservative to assume a smaller initial fluid mass. Therefore, the use of the HZP temperature for the determination of the initial RCS fluid mass was conservative relative to the AOR.

The limiting results (Table SRXB-34-1 of Reference 53) from the analyzed configurations showed that the system delivery boron concentration exceeded the anticipated shutdown margin concentration requirements. This requirement would be verified for each core reload as part of the cycle specific reload analysis.

The BAMT volume in the proposed TS Figure 3.1-1 reflected analytical results with inclusion of the margin to account for unusable tank inventory, the inventory associated with the level measurement uncertainty, the inventory associated with auxiliary spray, and the minimum vortex prevention level. The RWT volume requirement was significantly smaller than that required by TS LCO 3.5.4. For consistency, the larger volume from TS LCO 3.5.4 was specified for LCO 3.1.2.8.d (SRXB-34 of (Reference 53)). As for the TS required minimum boron concentration in the proposed TS Figure 3.1-1and TS LCO 3.1.2.8.d, a 100 ppm boron concentration uncertainty was added to the nominal concentration of the both BAMT and RWT. In addition, the proposed maximum concentration limit of 2200 ppm in the RWT was conservative with respect to assumptions used in the post-LOCA boron precipitation analysis and within the solubility limit based on the minimum temperature requirements.

Based on the above discussion, the NRC staff found that (1) the NRC-approved methods were used in determination of the required boron acid concentration and volume in the BAMT and RWT, (2) the results showed that the required shutdown margin in TS LCO 3.1.1.1 was maintained, and (3) the TS Figure 3.1-1 and TS LCO 3/4.1.2.8.d adequately reflected the required boron concentration and volume including uncertainties. Therefore, the NRC staff determined that the proposed values of the boron concentration and volume in TS Figure 3.1-1 and TS LCO 3/4.1.2.8.d were acceptable for the BAMT and RWT.

9. TS 3/4.1.3.4 Reactivity Control Systems - CEA Drop Time

The following TS items were proposed to change:

9.1 LCO would be changed from requiring the drop time of an individual CEA from a fully withdrawn position to its 90% insertion position be less than or equal to 3.2 seconds to less than or equal to 3.25 seconds.

9.2 Surveillance Requirement (SR) 4.1.3.4.b, “For specifically affected individuals CEAs…” would be changed to “For specifically affected individual CEAs…”

As stated in Section 2.8.5.0.3 of the licensing report (Reference 2), the CEA drop time of 3.25 seconds for 90 percent insertion was used for the non-LOCA transient analyses in support of the EPU application. Since the TS change correctly reflected the CEA drop time used in the acceptable non-LOCA analyses discussed in Section 2.8.5 of this SER, the NRC staff determined that the TS change was acceptable. Also, the proposed SR would involve a change from “individuals” to “individual” to correct a typo, which was an editorial change and did not change the TS requirements. Therefore, the NRC staff determined that the SR change was also acceptable.

10. TS 3/4.2.5, Power Distribution Limits – DNB Parameters

TS 3.2 5 was proposed to delete TS Table 3.2-2, which contains the limits for DNB-related parameters of (1) cold leg temperature, (2) pressurizer pressure, (3) axial shape index, and

(4) RCS flow rate. TS Table 3.2-2 would then be relocated to the core operating limits report (COLR).

The NRC staff determined that relocation of the limits of the first three parameters to the COLR was acceptable since those limits were previously allowed to be relocated to the COLR. However, the proposed COLR relocation of the limit of RCS flow rate was inconsistent with the NRC staff's position, which stated in an NRC letter from T. H. Essig of January 19, 1999 (ADAMS Accession No. 9901260003) that:

"… a change in RCS flow is an indication of physical change to the plant which should be reviewed by the NRC staff. Because of this, the staff recommended that if RCS flow rate were to be relocated to the COLR, the minimum limit for RCS total flow based on a staff approved analysis (e. g., maximum tube plugging) should be retained in the TS to assure that a lower flow rate than reviewed by staff would not be used…"

During the review, the NRC staff requested the licensee to address its compliance with the above NRC position. In response, the licensee revised, as shown in the RAI SRXB-36 response of FPL letter L-2011-534 (Reference 53) and TS changes in FPL letter L-2011-422 (Reference 62), LCOs 3.2.5.a and 3.2.5.b by referring the cold leg temperature and pressurizer pressure to Table 3.2-2 of the COLR, and changed LCO 3.2.5.d by referring the axial shape index to Figure 3.2-4 of the COLR. The licensee retained the RCS total flow rate in the LCO 3.2.5.c and deleted it from the COLR Table 3.2-2. Since the changes were consistent with the NRC's position, the NRC staff determined that the changes were acceptable. The total RCS flow rate in the TS would be changed from ≥ 335,000 gpm to ≥ 375,000 gpm. Since the RCS flow limit correctly reflected the value used in the acceptable safety analyses in support of the EPU applications, and therefore, the changes were acceptable.

The following changes were also acceptable since the changes were made to be consistent with the changes to LCO 3.2.5 (Reference 62) discussed above.

10.1 LCO 3.2.5 lead-in would delete "shown on Table 3.2-2" after "within the limits."

This change adequately reflected the proposed deletion of TS Table 3.2-2.

10.2 LCO 3.2.5.b would be changed from "Pressurizer Pressure" to "Pressurizer Pressure*" to add a new footnote. The added footnote stated that "Limit not applicable during either a THERMAL POWER ramp increase in excess of 5% of RATED THERMAL POWER or a THERMAL POWER step increase of greater than 10% of RATED THERMAP Power."

This footnote was relocated from TS Table 3.2.2 to be deleted. It did not change the condition of the pressurizer pressure limit in the current TS.

10.3 SR 4.2.5.1 would be changed from "Each of the parameters of Table 3.2-2 shall be …" to "Each of the DNB-related parameters shall be…"

The changes reflected the deletion of TS Table 3.2-2, and did not change the TS requirements.

10.4 SR 4.2.5.2 would be changed from "… within its limit by measurement* at least …" to "… within its limit by measurement** at least…" to shift the related footnote designation below the footnote that would be added to LCO 3.2.5.b. The current footnote would be changed from "*" to "**" and the threshold for the 18-month RCS total flow rate measurement would be changed from "80%" to "90%" of rated thermal power (RTP).

TS Amendment No. 145 restricted the maximum power level to 89 percent of 2700 MWt under certain conditions of the RCS flow and SG tube plugging until the Combustion Engineering model 3410 SGs were replaced. To conform to the operation power restriction, the footnote to TS SR 4.2.5.2 for the RCS flow rate determination was changed from 90 percent RTP to 80 percent RTP since the power level restriction of 89 percent RTP would have made flow measurement at or above 90 percent RTP infeasible. The SGs were replaced and these restrictions were no longer applicable. Since the current maximum power level is 100 percent RTP, the RCS flow rate determination power level was proposed to be reverted back to 90 percent RTP. The NRC staff found the proposed changes reflected the conditions of replaced SGs and were consistent with the earlier TS. Therefore, the changes were acceptable.

10.5 Table 3.2-2 would be deleted from the TS.

The deletion was consistent with the acceptable relocation of TS Table 3.2-2 to COLR, and therefore, was acceptable

11. Table 4.3-1, Reactor Protective Instrumentation Surveillance Requirements

The licensee has proposed to add notes 8 and 9 to meet the guidance of RG 1.105 and the clarifications provided in RIS 2006-17. Notes 8 and 9 meet the staff guidance and are acceptable.

12. TS 3/4.4.8, Reactor Coolant System – Specific Activity

LCO 3.4.8b is changed to read "...100/$\bar{E}$ microcuries/gram." to "518.9 microcuries/gram DOSE EQUIVALENT XE-133." The Applicability is changed from "MODES 1, 2, 3, 4 and 5." to "MODES 1, 2, 3, and 4." The actions were updated to reflect these changes and the footnote "*" was deleted. The licensee derived the proposed TS DE Xe-133 limit from the prior TS 100/E-bar limit for non-iodine isotopes, such that the air submersion dose produced by the non-iodine isotopes would be approximately the same.

The NRC staff's review found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 5 and the licensee's calculated dose results are given in Table 1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a DBLOCA will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

13. TS 3/4.4.2.2, Reactor Coolant System – Operating

The PSVs provide overpressure protection for the RCS. Together with the RPS, the PSVs ensure that the RCS pressure meets the GDC 15 requirement in terms of the RCS design pressure safety limits. Compliance with the GDC 15 requirement is demonstrated in the analysis of the design-basis-events (DBEs).

The design opening pressure of the PSVs is 2500 psia. Current TS 3.4.2 specifies the lower and upper setpoints of the PSVs of 2435.3 psig (2450 psia) and 2535.3 psig (2550 psia), respectively. The lower and upper setpoints corresponds to a - 2% and +2% tolerance on the PSVs. The proposed TS 3.4.2.2 would change the lower and upper setpoints to 2410.3 psig (2425 psia) and 2560.3 psig (2575 psia), which correspond to a - 3% and + 3% tolerance on the PSV setpoint.

The licensee performed the DBE analysis at EPU conditions and discussed the analysis in licensing report Section 2.8.5 (Reference 2). Table SRXB-38-2 in FPL letter L-2011-534 (Reference 53) identified that the PSVs were credited in the DBE analysis for the following events:

1. Loss of Condenser Vacuum (LOCV)
2. FW Line Break (FLB)
3. Reactor Coolant Pump Sheared Shaft or Locked Rotor

For the analysis of the primary or secondary overpressurization case, the PSVs were set to the upper limit setpoint of 2575 psia, which was based on the nominal setpoint plus 3% tolerance. A higher setpoint would delay the PSV opening time and cause more decay heat remained in the RCS before the PSV opening, which maximized the peak RCS pressure, presenting a greater challenge to overpressure criteria. For the analysis of the departure from nucleate boiling (DNB) case, the PSVs were set to the lower limit setpoint of 2425 psia, which was based on the nominal setpoint minus 3% tolerance. A lower setpoint would open the PSV earlier and the earlier steam releases from the PSVs reduced the RCS pressure, which minimized the DNB ratio, presenting in a greater challenge to DNB. For the cases that would not result in an increase in the RCS pressure (and thus, would not open PSVs), the setpoint of 2575 psia was used.

The NRC reviewed the EPU analysis of the affected events and accepted the analysis. The bases of the NRC's acceptance were discussed in Sections 2.8.5.2.1, 2.8.5.2.4, and 2.8.5.3.2 of the SER for the LOCV, FLB and locked rotor event, respectively.

The NRC staff found that the proposed upper and lower setpoints of the PSVs were adequately used in the acceptable safety analysis, therefore, determined that the proposed setpoints were acceptable.

14. TS 3/4.4.9.3, Reactor Coolant System – Overpressure Protection System.

The following TS items would be changed:

14.1 Table 3.4-3, "Low Temperature RCS Overpressure Protection Range" and Table 3.4-4, "Minimum Cold Leg Temperature for PORV Use for LTOP": Operating Period EFPY would be changed from 55 to 47 EFPY.

The overpressure protection system is designed to prevent violation of the RCS P-T limits in the event of an overpressure event during low temperature operation. Operating period would be changed from 55 to 47 effective full power years (EFPY). The TS change would affect TS Table 3.4-3, "Low Temperature RCS Overpressure Protection Range," and Table 3.4-4, "Minimum Cold Leg Temperature for PORV Use for LTOP."

Section 2.8.4.3 of licensing report (Reference 2) discussed the analysis of the design basis events, the M&E addition events, for overpressure protection during low temperature operation. The analysis determined the peak RCS pressures for a spectrum of cases at EPU conditions and compared the peak pressures to the RCS P-T limits. The results showed that using the current PORVs and SDC valves lift settings, the existing RCS P-T limits were not exceeded for the overpressure protection range. The NRC staff has reviewed and accepted the M&E analysis for low temperature overpressure protection (LTOP). The bases of acceptance were discussed in Section 2.8.4.3 of this SER. Since the RCS P-T limits shown in TS Figures 3.4-2 and 3.4-3 remained valid for 47 EFPY vice 55 EFPY, the operating period in TS Tables 3.4-3 and 3.4-4 would be changed from 55 to 47 EFPY. The NRC staff found that the TS changes adequately reflected the P-T values used as acceptance criteria in the acceptable LTOP analysis for EPU conditions, and therefore, determined that the changes were acceptable.

14.2 Table 3.4-3: "Cold Leg Temperature - F°" would be changed to "Cold Leg Temperature, °F."

14.3 Table 3.4-4: The second and third columns would be changed to the same format as these columns in Table 3.4-3.

The proposed changes in above items 14.2 and 14.3 were editorial and do not change the TS requirements.

15. TS 3/4.5.1, Emergency Core Cooling System (ECCS) – Safety Injection Tanks (SIT)

The changes would affect the following TS items:

15.1 LCO 3.5.1.c – The SIT boron concentration would be changed from "between 1720 and 2100 ppm of boron" to "between 1900 and 2200 ppm of boron."

15.2 The footnote "*" in the APPLICABILITY section for Mode 3 with respect to the boron concentration requirement in the SITs, when pressurizer pressure is less than 1750 psia, would be also changed from "between 1720 and 2100 ppm of boron" to "between 1900 and 2200 ppm of boron."

The post-LOCA criticality analysis assumed a minimum boron concentration of 1800 ppm in the SITs and showed that the containment sump boron concentration would be greater than the post-LOCA critical boron concentration to the time of ECCS switchover to hot/clod leg recirculation. The proposed TS limit of 1900 ppm was based on the analytical value of 1800 ppm plus 100 ppm for uncertainty. The upper limit boron concentration of 2200 ppm was also conservative with respect to the assumption used in the LOCA long-term boron precipitation analysis, which assumed a boron concentration of 2600 ppm. The NRC staff has reviewed and accepted the post-LOCA criticality and LOCA long-term boron precipitation analyses with the bases discussed in Section 2.8.5.6.3 of this SE. Since the proposed boron concentration limits reflected adequately the values used in the acceptable analyses in support of the EPU application, the proposed TS changes were acceptable.

16. TS 3/4.5.2, ECCS Subsystems – Operating

The following TS items would be changed:

16.1 LCO 3.5.2.d, a new Footnote, "*" would be added stating "* One ECCS subsystem charging pump shall satisfy the flow path requirements of Specification 3.1.2.2.a or 3.1.2.2.d. The second ECCS subsystem charging pump shall satisfy the flow path requirements of Specification 3.1.2.2.b or 3.1.2.2.e." The changes provided a cross reference to TS 3.1.2.2, "Reactivity Control Systems – Flow Paths – Operating," to alert the operator that inoperability of one or both charging pumps could impact TS 3.1.2.2.

Since the changes would assure that ECCS sources credited in the analysis were available, the NRC staff determined that the changes would be improvements to the TS, and therefore, they were acceptable.

16.2 APPLICABILITY would be changed from "MODES 1, 2 and 3*" to "MODES 1, 2 and 3**," and

16.3 Footnote "* With pressurizer pressure greater than or equal to 1750 psia." would be changed to "** With pressurizer pressure greater than or equal to 1750 psia."

The changes in items 14.2 and 14.3 reflected the correct sequence of the footnotes after the changes in item 14.1 were added. The changes were editorial and acceptable.

16.4 Surveillance Requirement 4.5.2.f.1. would be revised from "… each automatic valve in the flow path actuates …" to "… each automatic valve in the flow paths actuates …,"

16.5 Surveillance Requirement 4.5.2.f.2.a. would be revised from "High-Pressure Safety Injection pump." to "High-Pressure Safety Injection pumps," and

16.6 Surveillance Requirement 4.5.2.f.2.b. would be changed from "Low-Pressure Safety Injection pump." to "Low-Pressure Safety Injection pumps."

The changes in items 14.4, 14.5 and 14.6 adding "s" to "path" and "pump" would make it clear that the flow paths rather than a single flow path are required to be tested, and both of the high pressure safety injection (HPSI) pumps and low pressure safety injection (LPSI) pumps are to be tested. The changes provided clarification to the required tests for the flow paths, HPSI and LPSI pumps. Therefore, the changes were improvements to the current TS and were acceptable.

16.7 A new Surveillance Requirement, "c. Charging Pumps," would be added to SR 4.5.2.f.2.

The changes would add the charging pumps to surveillance requirements for safety injection signal testing and include the charging pumps in the service testing program. The change were consistent with the ECCS sources credited in the EPU analysis, and therefore, acceptable.

16.8 Surveillance Requirement 4.5.2.g -. An underline "_" would be deleted.

The proposed removal of "_" was an editorial change and did not change the TS requirements, and was acceptable.

17. TS 3/4.5.4, Emergency Core Cooling systems – Refueling Water Tank

LCO 3.5.4.b – The RWT boron concentration would be changed from “between 1720 and 2100 ppm” to “between 1900 and 2200 ppm.”

The TS limits on RWT minimum water volume and boron concentration are to ensure that sufficient water is available within the containment to allow recirculation flow to the core, and that the reactor remains subcritical in the cold condition following mixing the RWT and the RCS water volumes with all control element assemblies (CEA) rods inserted, except for the most active CEA. The post-LOCA criticality analysis assumed a minimum boron concentration of 1800 ppm in the RWT and showed that the containment sump boron concentration would be greater than the post-LOCA critical boron concentration to the time of ECCS switchover to hot/clod leg recirculation. The proposed TS limit of 1900 ppm was based on the analytical value of 1800 ppm plus 100 ppm for uncertainty. The upper limit boron concentration of 2200 ppm was also conservative with respect to the assumption in the LOCA long-term boron precipitation analysis, which assumed a boron concentration of 2600 ppm. The NRC staff has reviewed and accepted the post-LOCA criticality and LOCA long-term boron precipitation analyses with the bases discussed in Section 2.8.5.6.3 of this SER. Since the proposed boron concentration limits reflected adequately the values used in the acceptable analyses in support of the EPU application, the proposed TS changes were acceptable.

18. TS 3/4.7.1.1, Plant Systems – Turbine Cycle – Safety Valves

The MSSVs provide overpressure protection for the RCS. Together with the RPS, the MSSVs ensure that the RCS pressure meets the GDC 15 requirement in terms of the RCS design pressure safety limits. Compliance with the GDC 15 requirement is demonstrated in the analysis of the design-basis-events (DBEs).

The design opening pressures the MSSVs are 1000 psia for the first bank of four valves and 1040 psia for the second bank of four valves on each of the steam lines. Current TS Table 3.7-2 specifies the MSSV lift setpoints, which are based on lift tolerances of +1 to -3% for all valves. For the EPU operation, the upper and lower setpoints shown in the proposed TS Table 3.7-2 are 1015.3 psig (1030 psia) and 955.3 psig (970 psia) for the first bank of MSSVs, and 1046.1 psig (1060.8 psia) and 994.1 psig (1008.8 psia) for the second bank of MSSVs. The proposed upper and lower setpoints correspond to a + 3% and - 3% tolerance on the first bank of the MSSVs and a +2% and -3% tolerance on the second bank.

The licensee performed the DBE analysis at EPU conditions and discussed the analysis in licensing report Section 2.8.5 (Reference 2). Table SRXB-39-1 in FPL letter L-2011-534 (Reference 53) identified that the MSSVs were credited in the DBE analysis for the following events:

1. Loss of Condenser Vacuum (LOCV)
2. FW Line Break (FLB)
3. Asymmetric SG Transient (ASGT)
4. Reactor Coolant Pump Sheared Shaft or Locked Rotor
5. Uncontrolled CEA Bank Withdrawal at Power (CEAWAP)
6. SG Tube Rupture (SGTR)

For the analysis of the primary or secondary overpressurization case, the maximum opening setpoints (based on the nominal setpoints plus +3% tolerance for the first bank and +2% for the second bank) were used. A higher setpoint would delay the MSSV opening time and caused more decay heat remained in the SG before the MSSV opening, which would maximize the peak SG pressure, presenting a greater challenge to overpressure criteria. For the SGTR analysis, the minimum tolerances were considered, because a lower opening setpoint would result in an earlier opening of the MSSVs and thus, maximize steam release for radiological dose analysis, presenting a greater challenge to the dose limits. For cases that would not result in an increase in the SG pressure, the setpoints of 1000 psia plus 3% tolerance on the first bank and 1040 psia plus 2% tolerance on the second bank were used. The assumption was acceptable since the MSSVs would not open during the transients and the setpoints would affect the result of the analysis.

The NRC reviewed the EPU analysis of the affected events and accepted the analysis. The bases of the NRC's acceptance were discussed in Sections 2.8.5.2.1, 2.8.5.2.4, 2.8.5.2.5, 2.8.5.3.2, 2.8.5.4.2, and 2.8.5.6.2 of the SER for the analysis of the LOCV, FLB, ASGT, locked rotor, CEAWAP, and SGTR, respectively.

The NRC staff found that the proposed upper and lower setpoints of the MSSVs were adequately used in the acceptable safety analysis, therefore, determined the proposed setpoints were acceptable

The acceptable TS Table 3.7-2 changes included:

18.1 Column header, "LIFT SETTING (+ 1% to - 3%)" would be changed to "LIFT SETTING *

18.2 A new footnote would be added to read, "* +/-3% for valves a through d and +2%/-3% for valves e through h".

The changes adequately reflected the proposed setpoint tolerances added to the nominal setpoints of the MSSVs as specified in below items 16.3 and 16.4, and therefore, were acceptable.

18.3 The upper limit for valves a through d (valves 8201, 8202, 8203, 8204 in SG A) and valves e through h (valves 8205, 8206, 8207, 8208 in SG B) was changed from "995.3 psig" (1010 psia) to "1015.3 psig" (1030 psia), which corresponded to the nominal setpoint of 1000 psia plus 3% tolerance, and

18.4 The upper limit for valves e through h (valves 8209, 8210, 8211, and 8212 in SG A) and valves 8213, 8214, 8215, and 8216 in SG B) was changed from "1035.7 psig" (1050.4 psia) to "1046.1 psig" (1060.8 psia), which corresponded to the nominal setpoint of 1040 psia plus 2% tolerance.

The upper MSSV setpoints in Items 16.3 and 16.4 reflected in the acceptable safegy analyses for applicable events, and therefore were acceptable. The lower setpionts for valves a through h in both SG A and SG remained unchanged

19. TS 3/4.8.1, Electrical Power System – A.C. Sources

19.1 The minimum volume of fuel in LCO 3.8.1.1.b.2 is changed from "…40,000…" to "…42,500…"

19.2 Surveillance Requirement 4.8.1.1.2.e.4.b is changed from "…4160 $\pm$ 420 volts and 60 $\pm$ 1.2 Hz…" to "…4160 $\pm$ 210 volts and 60 $\pm$ 0.6 Hz…."

19.2 Surveillance Requirement 4.8.1.1.2.e.5 is reformatted and ranges are made consistent with 4.8.1.1.2.e.4.b.

19.3 Surveillance Requirement 4.8.1.1.2.e.6.b is changed from "…4160 $\pm$ 420 volts and 60 $\pm$ 1.2 Hz…" to "…4160 $\pm$ 210 volts and 60 $\pm$ 0.6 Hz…."

19.4 LCO 3.8.1.2.b.2 is changed from "…40,000…" to "…42,500…"

The staff finds the minimum fuel volume acceptable since the TS change is related to the characteristics of the fuel oil being used for EPU operation, and it is not impacting the current design analysis to be able to handle emergency power loads following a LOOP event. Based on its review, the staff finds that the proposed TS changes to surveillance requirement relating to Steady-State Voltage and Frequency Limits are conservative, and the loadings remain within the EDG capability, the staff finds the proposed changes consistent with the guidance in the SRP and Position C.1.4 of RG 1.9; and therefore, are acceptable.

20. TS 3/4.9.1, Refueling Operations – Boron Concentration

This TS specifies the minimum boron concentration in the RCS and refueling cavity for Mode 6 operations.

TS ACTION 3.9.1 provides direction for emergency boration at a boration rate of greater or equal to 40 gpm in the event the boron concentration not maintained as specified in the COLR.

In ACTION Section, the minimum boron concentration in the borated water sources was proposed to change from "greater than or equal to 1720 ppm boron or equivalent" to "greater than or equal to 1900 ppm boron or equivalent." The NRC staff found that the proposed boron concentration was consistent with the minimum boron concentrations for the solution in the RWT, SIT, BAMT as discussed in item 5 of this section of this SER. Therefore, the NRC staff concluded that the boron concentration changes were acceptable.

21. TS 3/4.10.1, Special Test Exceptions – Shutdown Margin

The following TS items would be changed:

21.1 ACTION.a would be changed from "… continue boration at greater than or equal to 40 gpm of a solution containing greater than or equal to 1720 ppm boron or its equivalent" to "…continue boration at greater than or equal to 40 gpm of a solution containing greater than or equal to 1900 ppm boron or its equivalent", and

21.2 ACTION.b would be changed from "…continue boration at greater than or equal to 40 gpm of a solution containing greater than or equal to 1720 ppm boron" to "…continue boration at greater than or equal to 40 gpm of a solution containing greater than or equal to 1900 ppm boron."

This test exception is to permit the periodic verification of the actual versus predicted core reactivity condition occurring as a result of fuel burnup or fuel cycling operations. Since the revised minimum concentration of 1900 ppm for the boration flow to the RCS was consistent with the required minimum boron concentrations for the RWT, SIT, and BAMT discussed in above item 5 of this section of the SER, the NRC staff determined that the changes were acceptable.

22. TS 3.11.2.6, Radioactive Effluents – Gas Storage Tanks

LCO 3.11.2.6 is changed from "…285,000…" to "…202,500…"

The NRC staff conducted a confirmatory calculation and determined that the licensee's TS limit is acceptable. The staff's review also found that the licensee used analyses, assumptions, and inputs consistent with applicable regulatory guidance identified in this SE. Therefore, based on consistency with applicable guidance and engineering judgment, the NRC staff finds the proposed EPU acceptable with respect to the radiological consequences of an accidental WGDT release.

23. TS 6.8.4.h, Administrative Controls – Containment Leakage Rate Testing Program

23.1 Paragraph "a)" of TS 6.8.4.h, Containment Leakage Rate Testing Program, is incorporated into the introductory paragraph.

23.2 TS 6.8.4.h.b is deleted.

23.3 The second paragraph of TS 6.8.4.h is changed from "The peak calculated containment internal pressure for the design basis loss of coolant accident P_a, is 41.8 psig." to "The peak calculated containment internal pressure for the design basis loss of coolant accident P_a, is 43.48 psig."

TS 6.8.4.h.b is deleted because it refers to an event in the past that is not relevant to the current TS ("The first Type A test performed after the June 1992 Type A test shall be prior to startup following the SL2-17 refueling outage.")

For EPU, the licensee proposed to revise the 10 CFR Part 50 Appendix J TS containment integrated leakage rate test pressure (P_a) from 41.8 psig to 43.48 psig. The NRC staff agrees with the licensee because the proposed value of P_a is consistent with the calculated peak pressure for the limiting DBLOCA.

24. TS 6.9.1.11, Administrative Controls – Core Operating Limits Report (COLR)

The following TS items would be changed:

24.1 TS 6.9.1.11.b - The references for the COLR would be revised to reflect the revised analyses for EPU, and the following references would be deleted and replaced with "DELETED":

3. CENPD-199-P, Rev. 1-P-A, "C-E Setpoint Methodology: CE Local Power Density and DNB LSSS and LCO Setpoint Methodology for Analog Protection Systems," January 1986.

4. CENPD-266-P-A, “The ROCS and DIT Computer Code for Nuclear Design,” April 1983.
6. CENPD-188-A, “HERMITE: A Multi-Dimensional Space – Time Kinetics Code for PWR Transients,” July 1976.
7. CENPD-153-P, Rev. 1-P-A, “Evaluation of Uncertainty in the Nuclear Power Peaking Measured by the Self-Powered, Fixed Incore Detector System,” May 1980.
9. CEN-123(F)-P, “Statistical Combination of Uncertainties Methodology Part 2: Combination of System Parameter Uncertainties in Thermal Margin Analyses for St. Lucie Unit 1,” January 1980.
13. CEN-371(F)-P, “Extended Statistical Combination of Uncertainties,” July 1989.
15. CENPD-161-P-A, “TORC Code, A Computer Code for Determining the Thermal Margin of a Reactor Core,” April 1986.
16. CENPD-162-P-A, “Critical Heat Flux Correlation for C-E Fuel Assemblies with Standard Spacer Grids Part 1, Uniform Axial Power Distribution,” April 1975.
17. CENPD-207-P-A, “Critical Heat Flux Correlation for C-E Fuel Assemblies with Standard Spacer Grids Part 2, Non-uniform Axial Power Distribution,” December 1984.
18. CENPD-206-P-A, “TORC Code, Verification and Simplified Modeling Methods,” June 1981.
37. Letter, A.E. Scherer Enclosure 1-P to LD-82-001, “CESEC-Digital Simulation of a Combustion Engineering Nuclear Steam Supply System,” December 1981.
38. Safety Evaluation Report, “CESEC Digital Simulation of a Combustion Engineering Steam Supply System (TAC No.: 01142),” October 27, 1983.
39. CENPD-282-P-A, Volumes 1, 2 and 3, and Supplement 1, “Technical Manual for the CENTS Code,” February 1991, February 1991, October 1991, and June 1993, respectively.
40. CEN-121(B)-P, “CEAW, Method of Analyzing Sequential Control Element Assembly Group Withdrawal Event for Analog Protected Systems,” November 1979 (NRC SER dated December 21, 1999, Letter K. N. Jabbour (NRC) to T.F. Plunkett (FPL), TAC No. MA4523).
41. CEN-133(B), “FIESTA, A One Dimensional, Two Group Space-Time Kinetics Code for Calculating PWR Scram Reactivities,” November 1979 (NRC SER dated December 21, 1999, Letter K. N. Jabbour (NRC) to T.F. Plunkett (FPL), TAC No. MA4523).
44. CENPD-183-A, “C-E Methods for Loss of Flow Analysis,” June 1984.
45. CENPD-190-A, “C-E Method for Control Element Assembly Ejection Analysis,” July 1976.
46. CENPD-199-P, Rev. 1-P-A, Supplement 2-P-A, “CE Setpoint Methodology,” June 1998.
47. CENPD-382-P-A, “Methodology for Core Designs Containing Erbium Burnable Absorbers,” August 1993.
53. CEN-365(L), “Boric Acid Concentration Reduction Effort, Technical Bases and Operational Analysis,” June 1988 (NRC SER dated March 13, 1989, Letter J.A. Norris (NRC) to W.F. Conway (FPL), TAC No. 69325).
54. DP-456, F.M. Stern (CE) to E. Case (NRC), dated August 19, 1974, Appendix 6B to CESSAR System 80 PSAR (NRC SER, NUREG-75/112, Docket No. STN 50-470, “NRC SER – Standard Reference System, CESSAR System 80,” December 1975).

24.2 TS 6.9.1.11.b - Reference 64 would be rewritten to provide additional information as follows:

64. Letter, W. Jefferson Jr. (FPL) to Document Control Desk (USNRC), “St. Lucie Unit 2 Docket No. 50-389: Proposed License Amendment WCAP-9272 Reload Methodology and Implementing 30% Steam Generator Tube Plugging Limit,” L-2003-276, December 2003 (NRC SER dated January 31, 2005, Letter B.T. Moroney (NRC) to J.A. Stall (FPL), TAC No. MC1566).

24.3 TS 6.9.1.11.b - The following references would be added:

65. WCAP-14882-P-A, Rev. 0, “RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses,” April 1999.
66. WCAP-7908-A, Rev. 0, “FACTRAN - A FORTRAN IV Code for Thermal Transients in a UO2 Fuel Rod,” December 1989.
67. WCAP-7979-P-A, Rev. 0, “TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code,” January 1975.
68. WCAP-7588, Rev. 1-A, “An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Special Kinetics Methods,” January 1975.

24.4 TS 6.9.1.11.b - The supplement to Revision 1-P would be added to Reference 5, CENPD-275-P as follows:

5. CENPD-275-P, Revision 1-P-A, “C-E Methodology for Core Designs Containing Gadolinia-Urania Burnable Absorbers,” May 1988, & Revision 1-P Supplement 1-P-A, April 1999.

As stated in the response to RAI SRXB-65 (Reference 11), WCAP-10965-P-A, “ANC: A Westinghouse Advanced Nodal Computer,” was not included in TS 6.9.1.11.b because the ANC reference was covered under WCAP-11596-P-A, “Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores,” which was included as Reference 1 in TS 6.9.1.11.b. Since WCAP-10965-P-A was a referenced portion of WCAP-11569-P-A, the NRC staff agreed with the licensee that inclusion of WCAP-11569-P-A in the TS was sufficient for the ANC reference.

The changes discussed in item 19 of above Section 2.8.7.4 of this SER incorporated the changes to the analytical methods used to determine the core operating limits. The NRC staff found that (1) the deleted references were no longer used, (2) the added references documenting methods were previously approved by the NRC, and (3) the added references either identified the topical report(s) by number and title or identified the NRC staff’s SER for a plant specific methodology by NRC letter and date. These changes were consistent with guidance in NUREG-1432, the “Standard Technical Specifications for Combustion Engineering Plants” (which include St. Lucie 2). Specifically, Standard TS 5.6.5.b states that

“The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents: Identify the Topical Report(s) by number and title or identify the staff Safety Evaluation Report for a plant specific methodology by NRC letter and date."

Therefore, the NRC staff concluded that the changes were acceptable.

4.0 REGULATORY COMMITMENTS

The licensee has made the following regulatory commitment(s):

- Implement modification(s) to replace RDF Corporation resistance temperature detectors as described in licensing report section 2.3.1, Environmental Qualification of Electrical equipment.

- Implement modification(s) to the AC electrical buses as described in licensing report Section 2.3.3, AC Onsite Power System.

- Complete the modifications to remove the wave traps prior to operating St. Lucie 2 at its EPU ratings as discussed in Section 2.3.2 Offsite Power System – Switchyard Connections.

- Adopt MRP-227-A in place of the existing RVI inspection program.

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 STATE CONSULTATION

Based upon a letter dated May 2, 2003, from Michael N. Stephens of the Florida Department of Health, Bureau of Radiation Control, to Brenda L. Mozafari, Senior Project Manager, NRC, the State of Florida does not desire notification of issuance of license amendments.

6.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, 51.33, and 51.35, a draft Environmental Assessment and finding of no significant impact was prepared and published in the *Federal Register* on January 6, 2012 (77 FR 813). The draft Environmental Assessment provided a 30-day opportunity for public comment. The NRC staff received comments which were addressed in the final environmental assessment. The final Environmental Assessment was published in the *Federal Register* on July 6, 2012 (77 FR 40092). 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.

7.0 CONCLUSION

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

8.0 REFERENCES

1. *RS-001, Revision 0, "Review Standard for Extended Power Uprates".* December 2003.

2. *Licensing Report, Attachment 5 to Letter from Richard L. Anderson to NRC Re: St. Lucie Plant Unit 2, Docket No. 50-389, Renewed License No. NPF-16, License Amendment Request for an Extended Power Uprate, FPL Letter No. L-2011-021.* February 25, 2011. ADAMS Accession No. ML110730341.

3. *FPL Letter L-2007-198 from G.L. Johnston (FPL) to NRC, "St. Lucie, Unit 2 - Proposed License Amendment Update PT Curve and LTOP for 55 EFPY".* January 23, 2008. ADAMS Accession No. ML080290135.

4. *Letter from S. Lingam (NRC) to M. Nazar (FPL), "St.Lucie Plant, Unit No. 2 - Issuance of Amendment No. 154 Regarding Pressure Vessel Fluence to 55 Effective Full-Power Years of Operation".* January 29, 2009. ADAMS Accession No. ML090060049.

5. *FPL Letter L-2011-556 from R.L. Anderson to NRC, "St. Lucie, Unit 2 - Response to NRC Vessels & Internals Integrity Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request".* December 20, 2011. ADAMS Accession No. ML11362A382.

6. *NUREG-1779, "Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 & 2".* September 30, 2003. ADAMS Accession No. ML032940205.

7. *Letter from R. A. Nelson (NRC) to N. Wilmshurst (EPRI), "Final Safety Evaluation of EPRI Report, Materials Reliability Program Report 1016596 (MRP-227), Revision 0, 'Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines'".* June 22, 2011. ADAMS Accession No. ML111600498.

8. *FPL Letter L-2012-059 from R. L. Anderson to NRC, "Response to NRC Mechanical and Civil Branch (EMCB) Request for Additional Information Regarding Extended Power Uprate License Amendment Request".* February 29, 2012. ADAMS Accession No. ML12065A146.

9. *FPL Letter L-2012-177 from R. L. Anderson to NRC, "Supplemental Response to NRC Mechanical and Civil Branch (EMCB) Regarding Extended Power Uprate License Amendment Request".* April 19, 2012. ADAMS Accession No. ML12114A225.

10. *FPL Letter L-2011-220 from R. L. Anderson to NRC, "Response to NRC Electrical Engineering Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request".* June 16, 2011. ADAMS Accession No. ML11171A656.

11. *FPL Letter L-2011-532 from R. L. Anderson to NRC, "Response to NRC Reactor System Branch and Nuclear Performance Branch Request for Additional Information Regarding*

Extended Power Uprate License Amendment Request". January 14, 2012. ADAMS Accession No. ML12019A076.

12. *FPL Letter L-2011-346 from R. L. Anderson to NRC, "Response to NRC Instrumentation & Controls Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request".* August 25, 2011. ADAMS Accession No. ML11242A148.

13. *FPL Letter L-2011-566 from R. L. Anderson to NRC, "Response to NRC Instrumentation & Controls Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request".* January 14, 2012. ADAMS Accession No. ML12019A067.

14. *RIS 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications".* January 31, 2002. ADAMS Accession No. ML013530183.

15. *Caldon, Topical Report ER-80P, Revision 0, "Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the System".* March 1997. ADAMS Accession No. ML003670328.

16. *Caldon, Topical Report ER-157P, Revision 5, "Supplement to Topical Report ER-80P: Basis for a Power Uprate with the LEFM √TM or LEFM CheckPlusTM System".* October 2001. ADAMS Accession No. ML013440134.

17. *Letter from J.N. Hannon (NRC) to C.L. Terry (TU Electric), "Staff Acceptance of Caldon Topical Report ER-80P: Improving Thermal Power Accuracy While Increasing Power Level Using the LEFM System".* March 8, 1999. ADAMS Accession No. 9903190065.

18. *Letter from S.A. Richards (NRC) to M.A. Krupa (Entergy), "Review of Caldon, Inc. Engineering Report ER-157P".* December 20, 2001. ADAMS Accession No. ML013540256.

19. *Cameron, Engineering Report ER-740, Revision 0, "Bounding Uncertainty Analysis for Thermal Power Determination at St. Lucie Unit 1 & 2 Using the LEFM Checkplus™ System".* March 2010. ADAMS Accession No. ML110730306.

20. *ISA Standard ISA-RP67.04.02, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation".* January 2000.

21. *Regulatory Guide 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation".* December 1999. ADAMS Accession No. ML993560062.

22. *Cameron, Engineering Report ER-736, Revision 3, "Meter Factor Calculation and Accuracy Assessment for St. Lucie Unit 2"* . March 2010. ADAMS Accession No. ML110730306.

23. *FPL Letter L-2011-368 from R.L. Anderson to NRC, "Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request".* September 8, 2011. ADAMS Accession No. ML11255A006.

24. *FINAL SAFETY EVALUATION REGARDING REFERENCING THE SIEMENS TECHNICAL REPORT NO. CT-27332, REVISION 2, "MISSILE PROBABILITY ANALYSIS FOR THE SIEMENS 13.9 M2 RETROFIT DESIGN OF LOWPRESSURE TURBINE BY SIEMENS AG" (TAC NO. MB7964).* March 30, 2004. ADAMS Accession No. ML040930616.

25. *CENPD-140-A, "Description of the CONTRANS Digital Computer Code for Containment Pressure and Temperature Transient Analysis".* s.I. : Combustion Engineering, June 1976.

26. *FPL Letter L-2011-383 from R. L. Anderson to NRC, "Response to NRC Containment and Ventilation Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request".* September 22, 2011. ADAMS Accession No. ML11269A222.

27. *CEFLASH-4A, A FORTRAN77 Digital Computer Program for Reactor Blowdown analysis, CENPD-133, Supplement 5-A.* June 1985.

28. *Entergy Memorandum W3F1-99-0156 from C. M. Dugger (Waterford 3) to NRC, "Technical Specification Change Request NPF-38-224 Containment Cooling System Reduction in Operable Containment Fan Coolers".* October 18, 1999.

29. *FPL Letter L-2011-476 from R. L. Anderson to NRC, "Response to NRC Containment and Ventilation Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request".* November 7, 2011. ADAMS Accession No. ML11314A065.

30. *Letter from B. L. Mozafari (NRC) to J. A. Stall (FPL), "ST. LUCIE UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS REGARDING.* February 22, 2008. ADAMS Accession No. ML080430644.

31. *Westinghouse Electric Company, LLC, CENPD-132, supplement 4-P-A, "Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model".* April 2001. ADAMS Accession No. ML011030417.

32. *CENPD-139-P-A, "Fuel Evaluation Model".* July 1974.

33. *CENPD-404-P-A, Revision 0, "Implementation of ZIRLO Cladding Material in CE Nuclear Power Fuel Assembly Designs".* November 2001.

34. *CEN-161(B)-P-A, "Improvements to Fuel Evaluation Model".* August 1989.

35. *CEN-161(B)-P, Supplement 1-P-A, "Improvements to Fuel Evaluation Model".* January 1992.

36. *FPL Letter L-2012-122 from R. L. Anderson to NRC, "Response to NRC Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request".* April 5, 2012.

37. *FPL Letter L-2012-121 from R. L. Anderson to NRC, "Information Regarding Fuel Thermal Conductivity Degradation Provided in Support of the Extended Power Uprate License Amendment Request," (Attachments 1, 2, 3, and 4).* March 31, 2012.

38. *Memorandum from P. Clifford (NRC) to A. Mendiola (NRC), "FRAPCON-3.4 Fuel Rod Thermal-Mechanical Design Calculations for Saint Lucie – 2 Extended Power Uprate," Attachment 1.* March 2012.

39. *NUREG/CR-7022, Volume 1, "FRAPCON-3.4: A Computer Code for the Calculation of Steady-State, Thermal-Mechanical Behavior of Oxide Fuel Rods for High Burnup".* March 2011.

40. *FPL Letter L-2011-493 from R. L. Anderson to NRC, "Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request".* November 23, 2011.

41. *CEN-372-P-A, "Fuel Rod Maximum Allowable Gas Pressure".* May 1990.

42. *CENPD-275-P, Revision 1-P-A, "C-E Methodology for Core Designs Containing Gadolinia-Urania Burnable Absorbers".* May 1988.

43. *Westinghouse WCAP-10965-P-A, "A Westinghouse Advanced Nodal Computer Code".* September 1986.

44. *Westinghouse WCAP-11596-P-A, "Qualification of the PHOENIX-P/ANC Nuclear Design Systems for Pressurized Water Reactor Cores".* June 1988.

45. *WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology,".* s.l. : Westinghouse, July 1985.

46. *CEN-386-P-A, "Verification of the Acceptability of a 1-Pin Burnup Limit of 60 MWD/KgU for Combustion Engineering 16x16 PWR fuel".* s.l. : ABB CE Nuclear Fuel, August 1992.

47. *WCAP-11397-P-A, "Revised Thermal Design Procedure".* s.l. : Westinghouse, April 1989.

48. *WCAP-14565-P-A, Addendum 1, "Qualification of ABB Critical Heat Flux Correlations with VIPRE-01 Code".* s.l. : Westinghouse, June 2002.

49. *WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis".* s.l. : Westinghouse, October 1999.

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68. *SECY-92-223, "Resolution of Deviations Identified during the Systematic Evaluation Program".* 1992. ADAMS Accession No. ML003763736.

Attachment:
1. List of Application Supplements
2. List of Acronyms

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Date: September 24, 2012

Attachment 1

LIST OF APPLICATION SUPPLEMENTS

ADAMS Accession No.	Document Date	Title
ML110730116	02/25/2011	St. Lucie, Unit 2 - License Amendment Request for Extended Power Uprate.
ML11147A070	05/24/2011	St. Lucie Plant, Unit 2 - Response to NRC Request for Supplemental Information Regarding Acceptance of the Extended Power Uprate License Amendment Request.
ML11207A455	07/22/2011	St. Lucie, Unit 2, Information Regarding Anticipated Transients Without Scram (ATWS) Provided in Support of the Extended Power Uprate License Amendment Request.
ML11231A925	08/18/2011	St. Lucie Plant, Unit 2, Information Requested by NRC Reactor Systems Branch Regarding a Sample Case Study for Boron Dilution Event in Support of the Extended Power Uprate License Amendment Request.
ML11231A926	08/18/2011	St. Lucie, Unit 2, Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request.
ML11231A927	08/18/2011	St. Lucie, Unit 2, Response to NRC Fire Protection Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11241A171	08/25/2011	St. Lucie, Unit 2, Response to NRC Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11242A139	08/25/2011	St. Lucie Plant Unit 2 - Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request.
ML11242A148	08/25/2011	St. Lucie Plant, Unit 2, Response to NRC Instrumentation & Controls Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11242A167	08/29/2011	St. Lucie Plant Unit 2, Response to NRC Health Physics and Human Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11251A155	09/02/2011	St. Lucie, Unit 2 - Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11255A006	09/08/2011	St. Lucie, Unit 2 - Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request.
ML11255A007	09/08/2011	St. Lucie, Unit 2 - Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request.
ML11269A222	09/22/2011	St. Lucie, Unit 2 - Response to NRC Containment and Ventilation Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11290A065	10/05/2011	Response to NRC Accident Dose Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.

ADAMS Accession No.	Document Date	Title
ML11285A047	10/10/2011	St. Lucie, Unit 2 - Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information and Supplemental Information Regarding Extended Power Uprate License Amendment Request.
ML11287A039	10/12/2011	St. Lucie Plant, Unit 2 - Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request.
ML11290A238	10/12/2011	St. Lucie Plant, Unit 2 - Response to NRC Request for Additional Information (RAI) re Extending Power Uprate License Amendment Request.
ML11306A018	10/31/2011	St. Lucie, Unit 2 - Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request.
ML11308B350	11/02/2011	St. Lucie, Unit 2, Response to NRC Instrumentation & Controls Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11312A135	11/03/2011	St. Lucie Plant, Unit 2 - Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request.
ML11314A111	11/04/2011	St. Lucie, Unit 2, Revision to Extended Power Uprate License Amendment Request Proposed Technical Specification 5.6, Design Features - Fuel Storage - Criticality.
ML11314A065	11/07/2011	St. Lucie, Unit 2, Response to NRC Containment and Ventilation Branch Request for Additional Information Regarding Extended Power Uprate License Amendment.
ML11319A225	11/14/2011	St. Lucie, Unit 2 - Response to NRC Component Performance and Testing Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11320A285	11/14/2011	St. Lucie Plant Unit 2, Response to NRC Health Physics and Human Performance Branch Request for Additional Information Regarding the Extended Power Uprate License Amendment Request.
ML11320A286	11/14/2011	St. Lucie, Unit 2, Response to NRC Accident Dose Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11332A071	11/23/2011	St. Lucie Plant, Unit 2,- Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11332A072	11/23/2011	St. Lucie Plant, Unit 2, Response to NRC Reactor Systems Branch Request for Additional Information Regarding the Extended Power Uprate License Amendment Request.
ML11332A133	11/23/2011	St. Lucie Plant Unit 2 - Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11350A245	12/08/2011	St. Lucie, Unit 2 - Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.

ADAMS Accession No.	Document Date	Title
ML11354A234	12/14/2011	St. Lucie, Unit 2, Response to Balance-of-Plant Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11362A382	12/20/2011	St. Lucie, Unit 2 - Response to NRC Vessels & Internals Integrity Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11364A043	12/27/2011	St. Lucie Plant Unit 2 - Response to NRC Steam Generator Tube Integrity and Chemistry Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12004A088	12/29/2011	St. Lucie, Unit 2, Response to NRC Reactor System Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12019A067	01/14/2012	Response to NRC Instrumentation & Controls Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12019A074	01/14/2012	St. Lucie Plant, Unit 2, Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12023A030	01/18/2012	St. Lucie, Unit 2 - Response to NRC Reactor System Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12023A031	01/18/2012	St. Lucie Plant, Unit 2, Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12025A082	01/21/2012	St. Lucie, Unit 2 - Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12025A196	01/21/2012	St. Lucie Plant Unit 2 - Response to NRC Reactor System Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12065A148	02/29/2012	St. Lucie Plant, Unit 2, Response to NRC Mechanical and Civil Engineering Branch (EMCB) Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12068A370	03/06/2012	St. Lucie Plant, Unit 2, Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12069A172	03/06/2012	St. Lucie Plant, Unit 2 - Response to NRC Mechanical and Civil Engineering Branch (EMCB) Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12072A040	03/08/2012	St. Lucie, Unit 2, Response to NRC Steam Generator Tube Integrity and Chemistry Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12079A013	03/15/2012	St. Lucie, Unit 2, Response to Nuclear Performance and Code Review Branch Request for Additional Information Identified During an Audit of Analyses Supporting the Extended Power Uprate License Amendment Request.

ADAMS Accession No.	Document Date	Title
ML12079A177	03/16/2012	St. Lucie, Unit 2, Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12080A104	03/17/2012	St. Lucie Plant, Unit 2 - Response to NRC Nuclear Performance & Code Review Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12080A138	03/17/2012	St. Lucie Plant Unit 2, Response to Request for Additional Information Identified During Audit of the Loss of Coolant Accident Safety Analyses Calculations for the Extended Power Uprate License Amendment Request.
ML12087A237	03/25/2012	St. Lucie Plant, Unit 2, Response to Request for Additional Information Identified During Audit of the Reactor Systems Branch (SRXB) Fluid System Analyses for the Extended Power Uprate License Amendment.
ML12094A311	03/31/2012	St. Lucie Plant, Unit 2, Response to NRC Steam Generator Tube Integrity and Chemical Engineering Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12094A312	03/31/2012	St. Lucie Plant, Unit 2 - Information Regarding Fuel Thermal Conductivity Degradation Provided in Support of the Extended Power Uprate License Amendment Request.
ML12097A529	04/05/2012	St. Lucie, Unit 2, Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12097A542	04/05/2012	St. Lucie, Unit 2 - Response to NRC Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12102A110	04/06/2012	St. Lucie Plant, Unit 2 - Response to Request for Additional Information Identified During Audit of the Non-Loss of Coolant Accident Safety Analyses Calculations for the Extended Power Uprate License Amendment Request.
ML12103A146	04/10/2012	St. Lucie Plant Unit 2, Response to Request for Additional Information Identified During Audit of the Reactor Systems Branch (SRXB) Fluid System Analyses for the Extended Power Uprate License Amendment Request.
ML12114A221	04/19/2012	St. Lucie, Unit 2 - Supplemental Response to NRC Mechanical and Civil Engineering Branch (EMCB) Regarding Extended Power Uprate License Amendment Request.
ML12114A224	04/19/2012	St. Lucie, Unit 2, Response to NRC Accident Dose Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12114A225	04/19/2012	St. Lucie, Unit 2, Supplemental Response to NRC Mechanical and Civil Engineering Branch (EMCB) Regarding Extended Power Uprate License Amendment Request.

ADAMS Accession No.	Document Date	Title
ML12114A229	04/19/2012	St. Lucie Plant Unit 2 - Response to NRC Mechanical and Civil Engineering Branch (EMCB) Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12114A230	04/19/2012	St. Lucie Plant Unit 2, Supplemental Information for Extended Power Uprate License Amendment Request (LAR) Section 2.6.1 Primary Containment Functional Design.
ML12114A232	04/19/2012	St. Lucie Plant Unit 2 - Response to NRC Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12115A180	04/19/2012	St. Lucie Plant, Unit 2, Response to NRC Nuclear Performance and Code Review Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12124A065	04/30/2012	St. Lucie Plant, Unit 2, Response to Request for Additional Information on Extended Power Uprate License Amendment Request - Supplement to Proposed Technical Specification Changes Related to Spent Fuel Storage Requirements.
ML12130A478	05/04/2012	St. Lucie Plant Unit 2 - Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12132A414	05/07/2012	St. Lucie, Unit 2 - Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12143A347	05/18/2012	St. Lucie Plant, Unit 2 - Supplemental Response to NRC Mechanical and Civil Engineering Branch (EMCB) Regarding Extended Power Uprate License Amendment Request.
ML12207A076	07/23/2012	Supplemental Information Related to the Control Element Assembly Reactivity Insertion Curve for the Extended Power Uprate License Amendment Request.

Attachment 2

LIST OF ACRONYMS

A	ampere
AAC	alternate ac sources
AC or ac	alternating current
ADAMS	Agencywide Documents Access and Management System
ADV	atmospheric dump valve
AEC	Atomic Energy Commission
AES	air evacuation system
AFT	as-found tolerance
AFW	auxiliary feedwater
AFWS	auxiliary feedwater system
AIF	Atomic Industrial Forum
AISC	American Institute of Steel Construction
ALARA	as low as reasonably achievable
ALT	as-left tolerance
AMP	aging management program
AMSAC	ATWS [anticipated transient without scram] mitigating system actuation circuitry
ANO-2	Arkansas Nuclear One, Unit 2
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	anticipated operational occurrence
AOR	analysis on record
AOT	allowed outage time
AOV	air operated valve
APCF	actual pressure correction factors
ARAVS	auxiliary and radwaste area ventilation system
ARI	alternate rod insertion
ART	adjusted reference temperature
ASGT	asymmetric steam generator transient
ASME	American Society of Mechanical Engineers
AST	alternative source term
ASTM	American society for Testing and Materials
ATWS	anticipated transient without scram
B&PV	boiler and pressure vessel

B&W	Babcock & Wilcox
BL	bulletin
BOC	beginning of cycle
BOL	beginning of life
BOP	balance-of-plant
BRS	boron recovery system
BTP	branch technical position
BWR	boiling-water reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
C	Celsius
cal/gm	calories per gram
CASS	cast austenitic stainless steel
CCF	common cause failure
CCW	component cooling water
CDF	core damage frequency
CE	Combustion Engineering
CEA	control element assembly
CEDE	committed effective dose equivalent
CEDM	control element drive mechanism
CEOG	Combustion Engineering Owners Group
CF	chemistry factor
CFC	containment fan cooler
Cfm	cubic feet per minute
CFR	*Code of Federal Regulations*
CFS	condensate and feedwater system
CHF	critical heat flux
CIAS	containment isolation actuation signal
CLB	current licensing basis
CLTP	current licensed thermal power
CPU	central processing unit
CR	control room
CRAC	control room air conditioning
CRAVS	control room area ventilation system
CRDA	control rod drop accident

CRDM	control rod drive mechanism
CRDS	control rod drive system
CREVS	control room emergency ventilation system
CRHE	control room habitability envelope
CS	containment spray
CSB	core support barrel
CsI	cesium iodide
CST	condensate storage tank
CUF	cumulative usage factor
CVCS	chemical and volume control system
CWS	circulating water system
DAFAS	diverse auxiliary feedwater actuation system
DBA	design-basis accident
DBLOCA	design-basis loss-of-coolant accident
DC or dc	direct current
DCF	dose conversion factor
DCS	distributed control system
DE	dose equivalent
DEHLS	double-ended hot leg slot
DF	decontamination factor
DG	draft guide
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DP	differential pressure
dpa	displacements per atom
DSS	diverse scram system
DTT	diverse turbine trip
EAB	exclusion area boundary
ECCS	emergency core cooling system
EDE	effective dose equivalent
EDG	emergency diesel generator
EEQ	electrical equipment qualification
EFDS	equipment and floor drainage system
EFPY	effective full-power year

EOC	end of cycle
EOL	end of life
EOP	emergency operating procedure
EPG	emergency procedure guideline
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
ESFVS	engineered safety feature ventilation system
F	Fahrenheit
F&O	fact and observation
FAC	flow-accelerated corrosion
FGR	Federal Guidance Report
FCM	fuel centerline melt
FEM	finite element method
FFBT	failure of the fast bus transfer
FHA	fuel-handling accident
FHB	fuel-handling building
FIV	flow-induced vibration
FIVE	Fire Induced Vulnerability Evaluation
FMP	fatigue monitoring program
FPL	Florida Power & Light Company
FPP	fire protection program
FPS	fire protection system
F_Q	total peaking factor
FSAR	Final Safety Analysis Report
FTSP	field trip setpoint
FW	feedwater
FWLB	feedwater line break
GALL	General Aging Lessons Learned
GDC	general design criterion (or criteria)
GL	generic letter
gpm	gallons per minute

GSI	generic safety issue
GWd/MTU	gigawatt days per metric ton of uranium
GWMS	gaseous waste management system
HELB	high-energy line break
HEP	human error probability
HEPA	high-efficiency particulate air
HFE	human factors engineering
HFP	hot full power
HI	Hydraulic Institute
HID	high impact design
hp	horse power
HP	high pressure
HPSI	high-preessure safety injection
HRA	human reliability analysis
HTP	high thermal power
HX	heat exchanger
Hz	Hertz
HZP	hot zero power
I&C	instrumentation and controls
I&E	inspection and evaluation
IASCC	irradiation-assisted stress-corrosion cracking
ICW	intake cooling water
ID	inside diameter
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	intergranular stress-corrosion cracking
IN	information notice
INPO	Institute for Nuclear Power Operations
IOMSSV	inadvertent opening of a main steam safety valve
IPB	isolated phase bus
IPCF	indicated pressure correction factors
IPE	individual plant examination
IPEEE	individual plant examination of external events
IR	insulation resistance
ISA	Instrument Society of America

ISG	interim staff guidance
ISI	inservice inspection
IST	inservice testing
JFD	joint frequency distribution
kA	Kilo Ampere
ksi	kilopound-force per square inch
kV	Kilo Volt
kW	Kilo Watt
LAR	license amendment request
LBB	leak before break
LBLOCA	large-break loss-of-coolant accident
lbm/sec (or /hr)	pounds mass per second (or per hour)
LCO	limiting condition for operation
LEFM	leading-edge flow meter
LERF	large early release frequency
LHR	linear heat rate
LLHS	light load handling system
LOAC	loss of AC electric power
LOCA	loss-of-coolant accident
LOCF	loss of normal coolant flow
LOEL	loss of external load
LONF	loss of normal FW
LOOP	loss of offsite power
LPD	local power density
LPSI	low-pressure safety injection
LPZ	low population zone
LRA	license renewal application
LR/SB	locked rotor or shaft break
LSSS	limiting safety system setting
LST	lowest service temperature
LTOP	low-temperature overpressure protection
LWMS	liquid waste management system
M&E	mass and energy
MAAP	Modular Accident Analysis Program

MBtu	million british thermal units
MC	main condenser
MCC	motor control center
MCES	main condenser evacuation system
MDNBR	minimum departure from nucleate boiling ratio
MEDP	maximum expected differential pressure
mFDI	modified duty index
MFIV	main feedwater isolation valve
MFW	main feedwater
MOV	motor-operated valve
MRP	Materials Reliability Program
MSIS	main steam isolation signal
MSIV	main steam isolation valve
MSIVLCS	main steam isolation valve leakage control system
MSLB	main steamline break
MSR	moisture separator reheater
MSSS	main steam supply system
MSSV	main steam safety valve
MT	main transformer
MTC	moderator temperature coefficient
MTO	margin-to-overfill
MUR	measurement uncertainty recapture
mV	millivolt
MVA	megavolt ampere
MW	Megawatt
MWd/MTU	megawatt days per metric ton of uranium
MWe	Megawatt electric
MWt	megawatt thermal
NAI	Numerical Applications, Inc.
NEI	Nuclear Energy Institute
NFV	new fuel storage vault
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation

NRS	narrow range span
NSSS	nuclear steam supply system
NTSP	nominal trip setpoint
O&M	operations and maintenance
OBE	operating basis earthquake
OD	outside diameter
OL	operability limit
OMS	overpressure mitigation system
ONP	off-normal operating procedures
OOS	out of service
OTC	once through cooling
P-T	pressure-temperature
PAOT	post-accident operability time
PATP	power ascension and testing plan
pcm	percent millirho
PORV	power-operated relief valve
ppm	parts per million
PRA	probabilistic risk assessment
PRT	pressurizer relief tank
PSHT	preservice hydrostatic test
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PSV	pressurizer safety valve
PT	potential transformer
PTS	pressurized thermal shock
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
QT	quench tank
R	Rankine
RAB	reactor auxiliary building
RAI	request for additional information
RCB	reactor containment building
RCIC	reactor core isolation cooling

RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
rem	Roentgen equivalent man
RFO	radial power fall-off
RG	regulatory guide
RHR	residual heat removal
RIS	Regulatory Issue Summary
RLE	reference leg effect
rpm	revolutions per minute
RPS	reactor protection system
RPV	reactor pressure vessel
RS	review standard
RSAC	reload safety analysis checklist
RSG	replacement steam generator
RT	radiography techniques
RTD	resistance temperature detector
RTDP	revised thermal design procedure
RTP	rated thermal power
RV	reactor vessel
RVI	reactor vessel internals
RVID	Reactor Vessel Integrity Database
RWCS	reactor water cleanup system
RWT	refueling water tank
SAFDL	specified acceptable fuel design limit
SAG	severe accident guideline
SAL	safety analysis limit
SAPP	safety analysis plant parameters
SAR	Safety Analysis Report
SBLOCA	small break loss of-coolanf accident
SBO	station blackout
SBCS	steam bypass control system
SBVS	shield building ventilation system
SCC	stress-corrosion cracking

SDC	shutdown cooling
SE	safety evaluation
SER	Safety Evaluation Report
SFP	spent fuel pool
SFPAVS	spent fuel pool area ventilation system
SFPCCS	SFP cooling and cleanup system
SG	steam generator
SGBS	steam generator blowdown system
SGTR	steam generator tube rupture
SGTS	standby gas treatment system
SIAS	safety injection actuation signal
SIS	system impact study
SIT	safety injection tank
SLCS	standby liquid control system
SPDS	safety parameter display system
SR	Surveillance Requirement
SRP	Standard Review Plan
SRV	safety relief valve
SSC	structures, systems, and component
SSE	safe-shutdown earthquake
SST	service station transformer
ST	setting tolerance
SUT	startup transformers
SWMS	solid waste management system
SWS	service water system
T-H	thermal-hydraulic
TAVS	turbine area ventilation system
TBS	turbine bypass system
TCD	thermal conductivity degradation
TCS	turbine control system
TCV	turbine control valve
TDAFW	turbine driven auxiliary feedwater
TEDE	total effective dose equivalent
TGSCC	transgranular stress corrosion cracking

TID	total integrated dose
TLAA	time-limited aging analysis
TLOFW	total loss of feedwater
TLU	total loop uncertainty
TM/LP	thermal margin/low pressure
TLOFW	total loss of feedwater
TS	technical specification
TSC	technical support center
TSF	threaded structural fastener
UAT	unit auxiliary transformer
UHS	ultimate heat sink
USE	upper shelf energy
UT	ultrasonic testing
V	volt
Vdc	volts DC
VCT	volume control tank
VHPT	Variable high power trip
WCAP	Westinghouse Commercial Atomic Power (report)
WGDT	waste gas decay tank